BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NOS. 2019-224-E and 2019-225-E

In the Matter of:	)
	)
South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	))))))

DIRECT TESTIMONY OF KEVIN LUCAS

ON BEHALF OF

THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

** PUBLIC (REDACTED) VERSION **

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association (SEIA). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A2. I began my employment at SEIA in April 2017. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to advocate for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education and advocacy.

As Senior Director of Utility Regulation and Policy, I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on the New York Reforming the Energy Vision proceeding on rate design and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy (Alliance) from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University Of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION?

A3. No, I have not.

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A4. Yes. I have testified before the Maryland Public Service Commission in several rate cases and merger proceedings. Additionally, I have testified before the Maryland Public Service Commission in several rulemaking proceedings, technical conferences, and legislative-style panels, covering topics such as net metering, EmPOWER Maryland (Maryland's energy efficiency resource standard), and offshore wind regulation development.

I have also submitted testimony in rate cases and integrated resource plans before the Public Utility Commission of Texas, the Michigan Public Service Commission, the Public

Utility Commission of Nevada, the Arizona Corporation Commission, and the Colorado Public Utilities Commission. My complete CV is attached to my testimony.[1]

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. My testimony is provided on behalf of South Carolina Solar Business Alliance ("SCSBA").

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. In my testimony, I analyze Duke Energy Carolina's and Duke Energy Progress's ("Duke" or "the Company") 2020 Integrated Resource Plan ("IRP") filing and its comportment with the requirements of Act 62. I compare and contrast Duke's IRP filing to the recently rejected Dominion Energy South Carolina ("DESC") IRP and find Duke's IRP lacking on several specific points the Commission cited in its rejection of DESC's IRP in Order No. 2020-832. I also evaluate Duke's modeling approach and assumptions on solar and storage, pointing out areas where improvements are needed, and highlight the overlooked opportunity presented by the recent extension of the federal investment tax credit ("ITC") on the Company's resource plan. Further, I deconstruct Duke's natural gas forecast, a key driver to its IRP results, and show why its approach is flawed and must be rejected. Finally, I evaluate the benefits of broader regionalization in reducing the cost for maintaining resource adequacy and facilitating the integration of more renewable energy.

Q7. PLEASE SUMMARIZE YOUR FINDINGS.

A7. Duke must make material modifications to its IRP to comport with Act 62.[2] At the broadest level, the Company does not identify "the most reasonable and prudent means of meeting [its] energy and capacity needs," instead presenting six different portfolios with disparate and flawed assumptions and results.[3] As a result, in order to perform its statutory duties, the Commission must direct Duke to amend its IRP to include such a determination or do so itself.

[1] Exhibit KL-1, Kevin M. Lucas CV.
[2] Act 62 is the recently passed law that stipulates requirements for IRPs. The statute defines the filing process, required information, and approval criteria. This is Duke's first IRP submitted since the statue was signed into law in May 2019. S.C. Code Ann. § 58-37-40.
[3] S.C. Code Ann. § 58-37-40(C)(2).

Duke also fails to consider adding energy-only resources during years where there is no capacity need and does not use the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") energy storage costs, in direct conflict with the Commission's order rejecting DESC's IRP.

Duke also fails to present a robust risk analysis that would enable the Commission to determine if the proposed IRP is the most reasonable and prudent means of meeting the electrical utility's needs, balancing "foreseeable conditions" including "resource adequacy," "consumer affordability," "compliance with applicable state and federal environmental regulations," and "commodity price risks," as the statute requires.[4] Although Duke develops multiple scenarios and sensitivities, the risk analysis is primarily qualitative. The Company fails to adequately account for several fossil-fuel related risks, including limited availability of firm natural gas supply, regulatory risk associated with continued coal plant operation, and stranded natural gas infrastructure investments for several of its portfolios. It assumes operational dates for non-commercial technologies such as small modular reactors ("SMR") and hard-to-permit technologies such as pumped hydro that are inconsistent with its own development timelines for these projects.

Duke's IRP portfolio modeling also fails to "fairly evaluate[e] the range of demand-side, storage, and other technologies and services available to meet the utility's service obligations."[5] Duke bypassed or limited opportunities for the model to find optimal solutions, instead hardcoding many results rather than allowing the model to solve for the best solution. This was particularly true for energy-only resources, which were prohibited from selection by the model absent a capacity need. Duke's solar capital costs are reasonable, although they need to be updated based on the recent extension of the federal ITC, but its operation and maintenance ("O&M") costs do not reflect industry trends occurring in this space. The

[4] S.C. Code Ann. § 58-37-40(C)(2).
[5] S.C. Code Ann. § 58-37-40(B)(1)(e).

Company also erroneously inflates its energy storage cost assumptions, incorrectly claiming that other public forecasts do not adjust for factors such as depth-of-discharge limitations and battery degradation. It also fails to account for any benefit from shorter-duration or behind-the-meter energy storage systems. The result is a substantial overestimate of energy storage costs that may have prevented the modeling software from selecting the most cost-effective quantities.

The recent extension of the federal ITC is a major development that has not been included in the Company's IRP. While this is understandable given the extension occurred in late December 2020, the impact on the IRP's portfolios could be large enough to warrant inclusion at this point. Effectively, projects that are completed before the end of 2026 are now able to obtain higher ITCs than was assumed during Duke's IRP development. This argues in support of pulling up solar and solar plus storage procurements to capture the credit for the benefit of Duke's customers.

Aside from failing to properly analyze the risk associated with fossil fuel generation, Duke also uses highly questionable methodologies in the natural gas price forecast used in its modeling. Duke relies on financial instruments priced on illiquid and volatile ten-year market natural gas futures contract prices before shifting over five years to a fundamentals-based forecast. The result is gas prices that are substantially lower than fundamentals-based forecasts for 15 years – the entire duration of the IRP planning period. Duke also assumes available natural gas firm fuel supply at a reasonable cost despite the recent cancellation of the Atlantic Coast Pipeline ("ACP") and $1.2 billion write down of the Mountain Valley Pipeline ("MVP"). Coupled with this is a total lack of a coal fuel cost and fixed O&M cost sensitivity, despite the sizable regulatory risks associated with the continued operation of Duke's coal fleet. These fossil-fuel related risks are all asymmetrical, leading to scenarios that are more likely to understate than overstate the cost of operating a fossil-fuel-heavy fleet.

Much of Duke's modeling assumes that it operates on an islanded network with little ability to share capacity between its operating units or to import capacity from the many surrounding balancing areas. Despite this baseline assumption, Duke's own modeling shows the benefits of a more coordinated approach to planning; allowing DEC and DEP to plan as one unit delays the need to build new capacity and produces savings for its customers. Expanding this concept further through a regional market could bring even deeper savings to customers, increase the ability to integrate renewable energy, and increase reliability in extreme events.

Q8. PLEASE SUMMARIZE YOUR OVERALL RECOMMENDATIONS.

A8. I make the following recommendations with respect to Duke's IRP:

Items Related to Act 62

1. The Commission should not approve Duke's IRP but rather require modifications to comply with Act 62.
2. Duke should select a single portfolio as its most reasonable and prudent option.
3. Duke should use battery capital costs from NREL's ATB Advanced case, as was required in the DESC IRP Order.
4. Duke should allow the addition of new resources or PPAs even when there is not a capacity need, as was required in the DESC IRP Order.
5. Duke should redo its natural gas forecast methodology to deemphasize the impact of short-term market price volatility, as was required in the DESC IRP Order.
6. Duke should produce a more robust risk assessment of its proposed buildout of natural gas infrastructure, including risks associated with obtaining firm fuel supply and stranded assets.

Modeling Methodologies and Input Assumptions

7. Duke should update modeling to incorporate the impact of the extension of the federal ITC on solar and solar plus storage projects.
8. Duke should adjust its fixed O&M costs for solar to reflect the same regional discount from NREL ATB as in its capital costs and mirror its price decline over time.
9. Duke should use NREL ATB Advanced capital costs for its energy storage costs.
10. Duke should use an annual battery replenishment model for both its standalone storage and solar and storage projects.

11. Duke should not inflate its battery pack size assumptions as battery degradation and enhancement is already accounted for in NREL ATB's fixed O&M costs.

12. Duke should allow its model to select up to 1,500 MW and 1,000 MW of two-hour batteries in DEP and DEC, respectively.

13. Duke should perform an analysis to determine the actual mix of fixed-tilt and single-axis tracking systems in its territories and use that for all analyses that model existing solar.

14. Duke should update its assumptions on future builds of solar to be 100% single-axis tracking systems for large projects and at least 80% single-axis tracking systems for future PURPA projects.

15. Duke should eliminate the 500 MW per year interconnection limit for solar in all cases, instead using the higher 900 MW limits in its high renewables case.6

16. Duke should adjust the development timelines of SMR and pumped hydro to at least be consistent with its own assumptions and preferably to be more in line with development timelines from recent projects.

Natural Gas Price Forecast and Coal Price Forecast

17. Duke's natural gas price forecast should calculate three years of monthly market prices based on the average of the previous month's market settlement prices from the NYMEX NG futures contract.

18. Duke should calculate the average price from at least two fundamentals-based forecasts, at least one of which should be the most recent EIA AEO reference case.

19. Duke should create a composite natural gas price forecast by using market prices for months 1 through 18, linearly transition between market prices and the fundamentals-based forecast average from months 19 through 36, and use the fundamentals-based forecast average form month 37 forward.

20. In constructing its high- and low-price sensitivities, Duke should utilize its current "geometric Brownian Motion model" to construct 25th and 75th percentile projections for 36 months. It should also calculate the average of the appropriate high- and low-price scenario from two or more fundamentals-based forecasts and perform the same blending method over 36 months as was done in the base natural gas price forecast.

21. Duke should construct a high-cost scenario for coal that reflects the potential increase in capital costs or fixed O&M costs that may come with future regulations.

The Benefits of Regionalization

22. Duke should study the impact of enhancing its Joint Dispatch Agreement to allow for joint planning and firm capacity sharing between the DEC and DEP.

23. Duke should study potential benefits associated with forming or joining an RTO or energy imbalance market.

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[6] All references to solar capacity are in MW_{AC}.

Q9. WHAT DO YOU ANTICIPATE WILL BE THE RESULTS OF YOUR COMBINED RECOMMENDATIONS?

A9. I anticipate that when Duke reruns its models with the updated methodologies and input assumptions above that optimal portfolios will retire coal sooner and build less natural gas capacity, while also selecting more solar, storage, and solar plus storage projects earlier in the planning horizon. These portfolios will be more robust against potential fossil fuel price increases and regulatory risks associated with existing and new fossil fuel assets. It will also jump start Duke's progress towards its own net-zero goals by leveraging the extension of the ITC to the benefit of its customers. The additional analysis and results will enable the Commission to determine whether it is the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs" under the statute.

II. ACT 62 REQUIRES A DETERMINATION OF "THE MOST REASONABLE AND PRUDENT MEANS OF MEETING THE ELECTRICAL UTILITY'S ENERGY AND CAPACITY NEEDS AS OF THE TIME THE PLAN IS REVIEWED."

Q10. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A10. In this section, I discuss Duke's IRP in the context of Act 62 and the Commission's rejection of DESC's IRP. I explain how Duke has failed to identify "the most reasonable and prudent means of meeting [its] energy and capacity needs" (i.e., a "Preferred Resource Plan"), while simultaneously failing to provide the Commission with all the information it would need to determine the most reasonable and prudent means of meeting such needs. I discuss similarities between Duke's IRP and the recently rejected DESC IRP, and critique Duke's massive natural gas buildout in the context of its net-zero carbon goals. Finally, I analyze the limited risk analyses that Duke performed and put forth a simple yet insightful risk analysis to show the benefit of retiring coal plants early.

Q11. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A11. Duke's IRP fails to comply with Act 62. By failing to select a Preferred Resource Plan, the Company is sidestepping its responsibility under the Act. Further, Duke has not presented the Commission with sufficient information to evaluate which plan is the most reasonable and prudent. Act 62 requires Duke to do more than just present a suite of options, it must also do the hard work to determine and demonstrate which of those options meets the statutory test of being the most reasonable and prudent path forward.

Duke's IRP shares several characteristics with DESC's rejected plan. Specifically, it uses unrealistic energy storage costs, fails to allow energy-only resources to be selected by the model, and inappropriately applies short-term pricing to long-term fuel cost forecasts. The Commission should reiterate its position in this case and direct Duke to make the same corrections that it required of DESC.

Despite having a 2050 net-zero goal, Duke proposes a massive buildout of natural gas infrastructure, much of which is brought online just after the 2035 IRP planning horizon ends. Duke underestimates the risk associated with its fuel supply assumptions, modeling availability at constant prices for firm gas delivery to its new natural gas combined cycle units despite the recent cancellation and write down of two local pipelines. Its stranded asset analysis is woefully inadequate if it has any intention of meeting its 2050 net-zero goals.

In the absence of a quantitative risk analysis from Duke, I produced a similar analysis as was performed in the DESC case. Here, it demonstrates the risk / benefit of both the Base Case with Carbon and the Earliest Practicable Coal Retirement portfolios under a wide variety of fuel and CO_2 cost assumptions.

A. Act 62 Requires Duke to Select a Single Most Reasonable and Prudent Plan

Q12. WHAT IS ACT 62?

A12. Act 62, also known as the SC Energy Freedom Act, was a comprehensive piece of energy legislation signed into law in May 2019,[7] includes numerous provisions on renewable energy programs, net metering, avoided cost calculation, interconnection standards, and integrated resource planning. Section 7 of the Act overhauls the requirements for integrated resource plans for electric utilities, electric cooperatives, municipally owned electric utilities, and the South Carolina Public Service Authority, and for the first time requires PSC review and approval of a utility IRP in a contested evidentiary proceeding.

Q13. WHAT ARE SOME OF THE KEY CRITERIA DEFINED IN ACT 62?

A13. Act 62 requires that covered electricity providers file an IRP at least every three years, with updates submitted annually.[8] The IRP must include information such as the long-term forecast of the utility's sales and peak demand; data related to the utility's existing resources and retirement plans; several resource portfolios to evaluate a range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's obligations; and an analysis on the cost and reliability impacts of meeting projected energy and capacity needs, among others.

The Commission must hold a public hearing on the IRP in which interested parties may intervene and gather evidence. Within 300 days of the filing, the Commission must issue a final order approving, modifying, or denying the plan filed by the utility. This decision is based on whether the Commission determines that the proposed IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[9]

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[7] S.C. Code Ann. § 58-37-40. Bill text accessed 1/12/2021 at https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm.
[8] While Act 62 requires several types of electricity providers to file IRPs, my testimony is focused on the requirements for electric utilities.
[9] S.C. Code Ann. § 58-37-40(C)(2).

The Commission's decision must consider whether the plan appropriately balances several factors, including resource adequacy and planning reserve levels, consumer affordability and least cost, compliance with environmental regulations, power supply reliability, commodity price risks, diversity of generation supply, and other foreseeable conditions that the Commission determines to be for the public interest.[10] If the Commission finds the proposed IRP does appropriately balance these factors, it must approve the IRP.[11] If it does not reach this finding, it can reject or require modifications to the IRP.

Q14. DOES DUKE PRESENT A SINGLE PORTFOLIO THAT IT ADVOCATES AS THE "MOST REASONABLE AND PRUDENT MEANS" OF MEETING ITS NEEDS?

A14. No, it does not. Duke presents a suite of six resource portfolios, each with several sensitivities, that contain differing assumptions on key characteristics such as coal retirement timeline, renewable energy addition limits, carbon pricing, and fuel forecasts. Duke appears to construe the compilation of the six portfolios as its "plan" as defined by Act 62, rather than properly identifying each of the six portfolios as a "plan" to be analyzed under Act 62's balancing requirements.

The two Base Cases are described as "least cost" portfolios (one with and one without carbon policy), while the other four explore pathways under various carbon constraints.[12] The six portfolios are:

- **Base Case without Carbon Policy**: "least cost" portfolio assuming no carbon policy.
- **Base Case with Carbon Policy**: "least cost" portfolio assuming basic carbon policy.
- **Earliest Practicable Coal Retirement**: retires coal plants as soon as practicable and optimizes remaining portfolio to meet capacity need.
- **70% CO2 Reduction: High Wind**: 70% CO_2 reduction constraint is modeled with higher deployment of solar, onshore wind, and offshore wind.
- **70% CO2 Reduction: High SMR**: 70% CO_2 reduction constraint is modeled with higher deployment of solar, onshore with, and small modular reactors ("SMR").
- **No New Gas Generation**: High CO_2 reduction targeted while not adding any new natural gas generation.

[10] S.C. Code Ann. § 58-37-40(C)(2)(a-g).
[11] S.C. Code Ann. § 58-37-40(C)(2).
[12] DEC IRP Report at 11-12.

Duke's IRP Report misconstrues the South Carolina IRP requirements, claiming "[t]hese base case portfolios employ traditional least cost planning principles as prescribed in both North Carolina and South Carolina."[13]

Q15. IS "LEAST COST" PLANNING THE CURRENT SOUTH CAROLINA REQUIREMENT FOR IRPS?

A15. No. Act 62 specifically defines a different "most reasonable and prudent" standard for IRPs. While "least cost" is one of the balancing factors that the Commission must weigh, it is not confined to the least cost plan if more reasonable and prudent portfolios exist.

Q16. DOES ACT 62 REQUIRE THE IDENTIFICATION OF A SINGLE PORTFOLIO AS THE "MOST REASONABLE AND PRUDENT" MEANS TO MEETING FUTURE NEED?

A16. With the caveat that I am not an attorney and not offering a legal opinion, I believe it does. Act 62 enumerates factors the Commission must balance, including consumer affordability and least cost, commodity price risk, and diversity of generation supply.

The Commission has previously acknowledged that the utility should identify a Preferred Resource Plan in its IRP submittal. In its order rejecting DESC's IRP, it identified the steps in a common approach to IRPs as "(1) forecast future electricity demand; (2) identify the goals and regulatory requirements the process must meet; (3) develop a set of resource portfolios designed to achieve those goals; (4) evaluate those resource portfolios; and (**5) identify a preferred resource plan**."[14] It also noted that DESC "did not properly assess risk and uncertainty, as required by Act 62, when analyzing and **selecting a preferred resource plan**."[15]

By developing six different portfolios without specifying which it believes is the most reasonable and prudent, Duke has presented dramatically different futures while simultaneously providing insufficient guidance on how to weigh the portfolios against each other. The non-Base Case portfolios call for the earliest possible retirement of coal plants,

[13] DEC IRP Report at 12.
[14] Docket No. 2019-226-E - Order No. 2020-832 (Dec. 23, 2020) at 9. ("DESC IRP Order") (emphasis added).
[15] DESC IRP Order at 18. (emphasis added)

while others rely on Duke's economic modeling to determine when to retire plants. These two approaches produce meaningfully different results, with some coal units retiring three years earlier.[16] Solar deployment varies dramatically; the difference in the two Base Cases is nearly 4 GW across DEP and DEC, while the deep decarbonization scenarios roughly double solar deployment from 8.6 GW in the Base Case without Carbon Policy to 16.4 GW.[17] Two of Duke's scenarios rely on SMRs, one of which requires a unit to be online at the end of 2029. This timeline, by Duke's own estimate, would require development activity to begin in 2021 and construction to begin in 2023.[18]

Q17. DOES THE COMPANY OFFER ANY EXPLANATION OF WHY IT PRESENTED MULTIPLE PORTFOLIOS AND DID NOT IDENTIFY A SINGLE PORTFOLIO AS ITS MOST REASONABLE AND PRUDENT CHOICE?

A17. It does. Company witness Glen Snider expands on this decision. He states:

> In summary, fifteen-year integrated resource plans involve forecasting a multitude of economic, technical, and overall market variables… Uncertainties exist in any single long-range forecast and such uncertainty is exacerbated in an IRP since IRPs are a culmination of several forecasted variables which drive additional complexity into the planning process. The Companies believe that Act 62 recognizes this high degree of long-range uncertainty in that it calls for multiple portfolios to be examined to cover a range of these uncertainties…
>
> Given the varying perspectives of parties to this proceeding, we expect different views on the various portfolios presented in the 2020 IRPs. However, the IRPs as filed present a total plan that can adapt to changing standards, technology and policy decisions. We believe this is consistent with Act 62, which directs the Commission to approve the plan as reasonable and prudent at the time the plan was reviewed by taking into consideration if the plan appropriately balances various criteria addressing reliability, affordability, compliance with environmental regulations,

[16] "The earliest practicable retirement analysis resulted in the acceleration of Mayo Unit 1 from 2029 in the Base Cases to 2026 and Roxboro units 1 and 2 from 2029 to 2028, joining Roxboro 3 and 4 in that year." DEP IRP Report at 95.
[17] DEP IRP Report at 16.
[18] Exhibit KL-2, Duke Response to SCSBA's Second Request for Production to DEC/DEP ("SCSBA RFP 2") (producing Duke response to DR NCSEA 5-1).

> commodity price risk, diversity of supply, and other factors the Commission determines to be in the public interest. The IRPs filed by the Companies accomplish that goal.[19]

Q18. WHAT IS YOUR INTERPRETATION OF THIS STATEMENT?

A18. First, the testimony critically drops the word "most" from the "most reasonable and prudent" provision of Act 62. The Commission is not directed to "approve the plan as reasonable and prudent", it is directed to approve "the most reasonable and prudent plan." This is a crucial distinction and undermines Duke's position that Act 62's requirements can be met by simply providing multiple options for the Commission to review.

Duke is correct that parties will have "different views" on its portfolios. But Duke's submission of six different portfolios does not constitute a single plan; one cannot approve year 1 through 4 of Portfolio A before switching in year 5 through 12 to Portfolio B and then transitioning in year 13 through 15 to Portfolio C. Each of Duke's portfolios was created from internally consistent assumptions, rendering the piecemeal construction of a single portfolio from portions of each meaningless.[20]

Q19. WHAT IS YOUR OVERALL OBSERVATION ABOUT DUKE'S PRESENTATION OF ITS PORTFOLIOS IN THE IRP?

A19. Duke has failed to identify a Preferred Resource Plan that it contends is the most reasonable and prudent means of meeting its future needs. It has also failed to present a more robust analysis of the relative merits and associated risks of each portfolio. For instance, it did not include a deeper dive into the policy and technology advancements that may be needed for each portfolio and how Duke and other parties might accomplish them. As an example, a deeper analysis of the current state of next-generation nuclear technology might have shown that portfolios requiring SMRs to be online by 2029 may not be reasonable given that development on those units would have to begin this year to meet the timeline.

[19] Snider Direct at 35-36.
[20] This is a major issue with Duke's natural gas forecast, as discussed in Section IV below.

Further, Duke's lack of a robust risk analysis on its existing and planned fossil fuel plants is problematic. Its focus on PVRR comparisons under different fuel costs and CO_2 assumptions fails to quantify risk in any dimension beyond dollars. For instance, Duke made no effort to weigh the likelihood of a high-cost future compared to a low-cost future, despite the fact that its portfolios perform substantially differently under those conditions. It does not contemplate potential federal regulations that may require sizable capital upgrades to its coal fleet that adds risk disproportionately to certain portfolios. By presenting six very different futures with minimal analysis beyond top-level cost estimates to differentiate them, Duke has inappropriately left the Commission with the task of choosing a future for Duke without the requisite information required to make an informed choice.

B. *Duke's IRP Shares Characteristics with DESC's Rejected IRP*

Q20. HAS THE COMMISSION RULED ON ANY IRPS FILED UNDER THE NEW ACT 62 STATUTE?

A20. Yes. The Commission recently ruled on the IRP filed by DESC.[21] It found "significant deficiencies" in the IRP's candidate resource plans, modeling assumptions, and methodologies, and ultimately rejected the IRP.[22] The Commission provided specific direction to DESC to revisit topics such as its load forecasts, natural gas price forecast, energy storage cost assumptions, and modeling methodologies, among others.

Q21. DOES DUKE'S IRP CONTAIN SHORTFALLS THAT THE COMMISSION IDENTIFIED IN DESC'S IRP?

A21. Yes, it does. The Commission specifically criticized DESC's energy storage cost assumptions as "unreasonably high" for using a capital cost of $1,818/kW for systems with a 2022 in-service date, compared to results from the Santee Cooper RFI that showed $1,324/kW for total installed

[21] DESC IRP Order.
[22] *Id.* at 7.

cost for 2022 in-service date projects.[23] By this measure, Duke's battery storage costs are also unreasonably high; Duke assumes an installed cost of $[redacted]/kW for systems coming online in 2022.[24] The Commission directed DESC to use NREL ATB Low cost assumptions for energy storage, which, when adjusted to nominal dollars, forecast a capital cost of $1,140/kW in 2022, more in line with the RFI results.[25] I discuss Duke's problematic energy storage assumptions later in my testimony.[26]

The Commission also cited DESC for not considering the addition of new resources or PPAs when there was not a capacity need, failing to recognize the potential for energy-only resources to provide savings compared to the running costs of existing resources. It directed DESC to model the addition of new resources earlier in its planning horizon even when there was no capacity need.[27] Duke commits the same error, configuring its model to only allow new resource additions when there was a defined capacity need. This date of first need is forecasted for 2024 for Duke Energy Progress ("DEP")[28] and 2026 for Duke Energy Carolinas ("DEC")[29], potentially delaying cost-saving procurements for between three and five years. This delay is particularly problematic given the recent extension of the ITC; failing to advance renewable development in the next several years will forego the sizable tax benefit that could be passed on to Duke's customers afforded by the ITC extension.

The Commission also found DESC's natural gas forecast methodology, in which it applied escalators to current prices, was problematic as it overemphasized transient short-term market dynamics in its long-range forecast.[30] It noted that DESC's forecast has a consistent

[23] *Id.* at 50.
[24] Exhibit KL-3, Duke Response to SCSBA RFP 2 (producing Duke response to PSDR3-7 (Confidential - IRP Generic Unit Summary DEC 2020)).
[25] NREL 2020 ATB.
[26] See Section III, *infra*.
[27] DESC IRP Order at 32-33.
[28] Duke Energy Progress Integrated Resource Plan 2020 Biennial Report ("DEP IRP Report") at 114.
[29] Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report ("DEC IRP Report") at 113.
[30] DESC IRP Order at 67-68.

low bias compared to more robust fundamentals-based modeling such as the Energy Information Administration's ("EIA") 2020 Annual Energy Outlook ("AEO"), and directed DESC to use the high, base, and low cases from AEO 2020. Duke's natural gas forecast differs from DESC, but it also suffers from a mismatch between short-term price signals and fundamentals-based forecast and over-weights prices influenced by short-term volatility. I discuss Duke's natural gas forecast later in my testimony.[31]

Q22. WHAT DO YOU RECOMMEND REGARDING THESE ISSUES?

A22. I recommend that the Commission reiterate its direction on these topics in this proceeding and require Duke to adjust assumptions on capacity additions, energy storage costs, and natural gas forecasts as I discuss below.

C. Duke Fails to Present Sufficient Analyses Required to Determine the Reasonableness and Prudence of its Portfolios

Q23. WHAT, IF ANY, COMPARISON DOES DUKE OFFER ACROSS SCENARIOS THAT PROVIDES INSIGHT AS TO WHETHER A PORTFOLIO IS REASONABLE AND PRUDENT OR IS THE MOST REASONABLE AND PRUDENT?

A23. Duke provides basic information on the portfolios themselves (e.g. MW of assets deployed), the estimated present value of the revenue requirement ("PVRR") of the portfolio over the planning horizon, and an estimate of transmission investment required to interconnect the resources in the portfolio.[32] However, Duke's presentation of these figures lacks context.

The primary overview of the IRP Report shows the PVRR excluding the explicit cost of carbon, despite the fact that five of the six portfolios assume a carbon price is present and impacts the results. This makes it appear that the carbon reduction portfolios are considerably more expensive than the base portfolios.[33] However, if one pieces together information from the separate IRP reports, Duke's data shows that after including the cost of carbon, the

[31] See Section IV, *infra.*
[32] DEP IRP Report at 16.
[33] DEP IRP Report at 16.

incremental cost of the deep decarbonization portfolios is considerably lower than it initially appears.

For example, the incremental cost of the 70% CO_2 Reduction: High Wind over the Base without Carbon Policy is shown as $20.7 billion (35% higher than the base case) in Executive Summary, but this value falls to $12.4 billion (12.5% higher) with the base CO_2 and fuel cost assumptions when including the explicit cost of carbon in the PVRR, and to $6.0 billion (5.2% higher) under the high CO_2 and fuel cost assumptions when including the explicit cost of carbon in the PVRR.[34] Additionally, these figures are based on Duke's modeling, which as discussed later, contains several questionable assumptions that, when corrected, could lower the incremental cost of the deep decarbonization portfolios further. and potentially shift which portfolio becomes least-cost. Duke should be directed to clearly present comparisons with potential carbon pricing, consistent with the Commission's finding in the DESC IRP order that "it is in the public interest for the risk of potential carbon pricing to also be considered and balanced" under Act 62.[35]

Q24. ARE THERE OTHER METRICS THAT DUKE PRESENTS TO ASSIST IN THE COMPARISON BETWEEN PORTFOLIOS?

A24. Yes. It produced a heuristic denoted as "Dependency of Technology and Policy Advancement."[36] This qualitative measure represents the Company's observation on the complexity of realizing certain portfolios given the current state of policy and technology. For instance, it considers the Base Case without Carbon Policy portfolio as "Not dependent" on policy and technology evolution, indicating it can accomplish the portfolio's deployment within the existing constructs. The 70% reduction scenarios are denoted as "mostly dependent"

[34] DEP IRP Report, Tables 12-B and 12-C; DEC IRP Report, Tables 12-B and 12-C.
[35] DESC Order at 20.
[36] DEP IRP Report at 15.

(High Wind) and "completely dependent" (High SMR), suggesting that without substantial technology and policy development these portfolios cannot be realized.[37]

Q25. **HOW RIGOROUS WAS DUKE'S ANALYSIS OF THIS HEURISTIC?**

A25. It does not appear to be very robust. The Company notes challenges such as technology advancements, operational risks, siting/permitting/interconnection issues, and supply chain development. However, there is no discussion regarding how much of these advances will occur as a baseline in the next ten years, nor discussion about how feasible the policy changes would be to enact. I generally agree with the directionality of Duke's assessments (for instance, it is likely true that deploying SMRs will require more policy and technology advancement than deploying solar and storage), but I do not believe that one could assign a specific dependency score for each portfolio based on data presented in Duke's IRP reports.

D. Duke's Natural Gas Capacity Buildout Plan is Risky and Inconsistent with its 2050 Net-Zero Goals

Q26. **HOW DO THE LEVELS OF NATURAL GAS CAPACITY VARY AMONG THE SIX PORTFOLIOS?**

A26. There is a considerable variance between the portfolios. The Company currently operates 10,460 MW of natural gas units, split roughly equally between combustion turbines ("CTs") and combined-cycle ("CC") units.[38] Table 1 below shows the proposed incremental capacities under the various portfolios.

	By 2035			**By 2041**		
	CC	CT	**Total**	CC	CT	**Total**
2020 Capacity	4,940	5,520	**10,460**	4,940	5,520	**10,460**
Incremental Capacity						
Base without Carbon Policy	3,672	5,941	**9,613**	4,896	12,796	**17,692**
Base with Carbon Policy	3,672	3,656	**7,328**	4,896	10,054	**14,950**
Earliest Prac. Coal Retirement	3,672	5,941	**9,613**	3,672	10,968	**14,640**
70% CO2: High Wind	3,672	2,742	**6,414**	3,672	5,484	**9,156**
70% CO2: High SMR	2,448	3,656	**6,104**	2,448	6,398	**8,846**
No New Gas Generation	0	0	**0**	0	0	**0**

[37] DEP IRP Report at 16.
[38] 2020 IRP_ Model Inputs_NON-CONFIDENTIAL.

Table 1 - Natural Gas Additions by Portfolio

By 2035, the first three scenarios add three new 1,224 MW CCs while increasing CT capacity by roughly two-thirds (Base with Carbon Policy) or more than double (Base without Carbon Policy and Earliest Practicable Coal Retirement). The 70% CO2: High Wind adds fewer CTs through 2035, offset by increasing battery deployment. Unsurprisingly, the No New Gas Generation portfolio adds no new gas generation.

As dramatic as are the additions by 2035, the additional builds through 2040 are truly staggering. The two Base cases each add another 1,224 MW CC facility. The Base without Carbon Policy more than doubles incremental CTs, bringing nearly 7 GW of additional capacity online by 2041. The Base with Carbon Policy portfolio adds nearly as much, with 6.4 GW of new CTs. These additions represent the largest proposed natural gas expansion of any utility in the country by far.[39] Figures 1 and 2 below show the annual additions under each scenario, revealing that much of the natural gas build that was modeled rests just outside of the 15-year planning horizon in Duke's IRP.

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[39] *The Dirty Truth about Utility Climate Pledges*, Sierra Club, January 2021. Available at https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Final%20Greenwashing%20Report%20%281.22.2021%29.pdf.

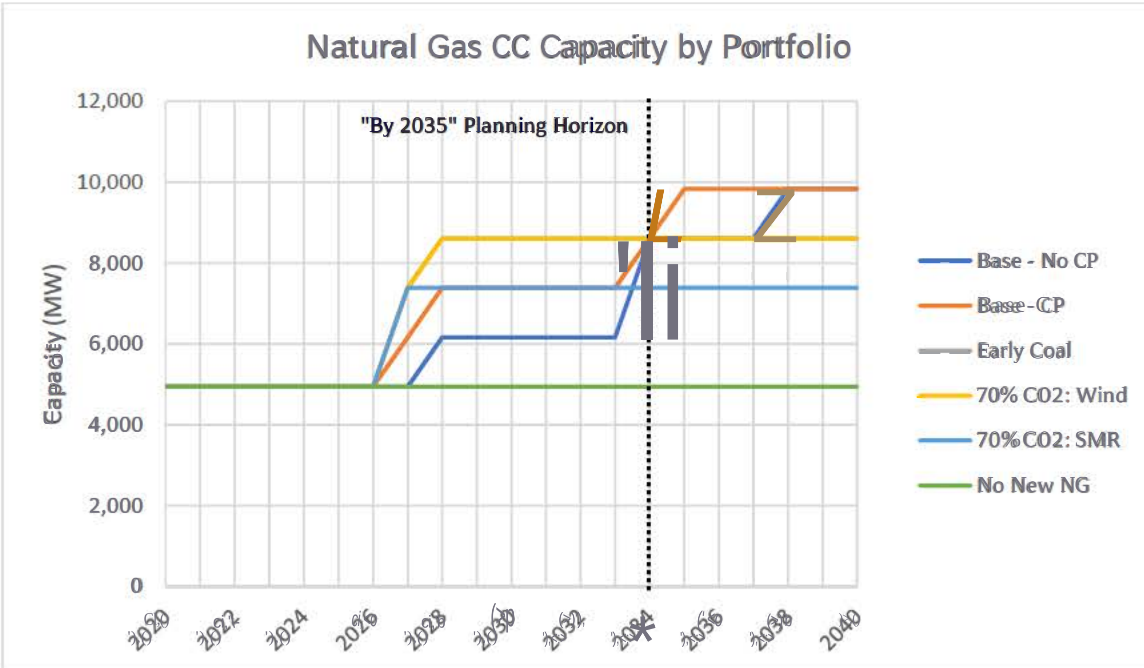

Figure 1 - Natural Gas CC Additions by Scenario

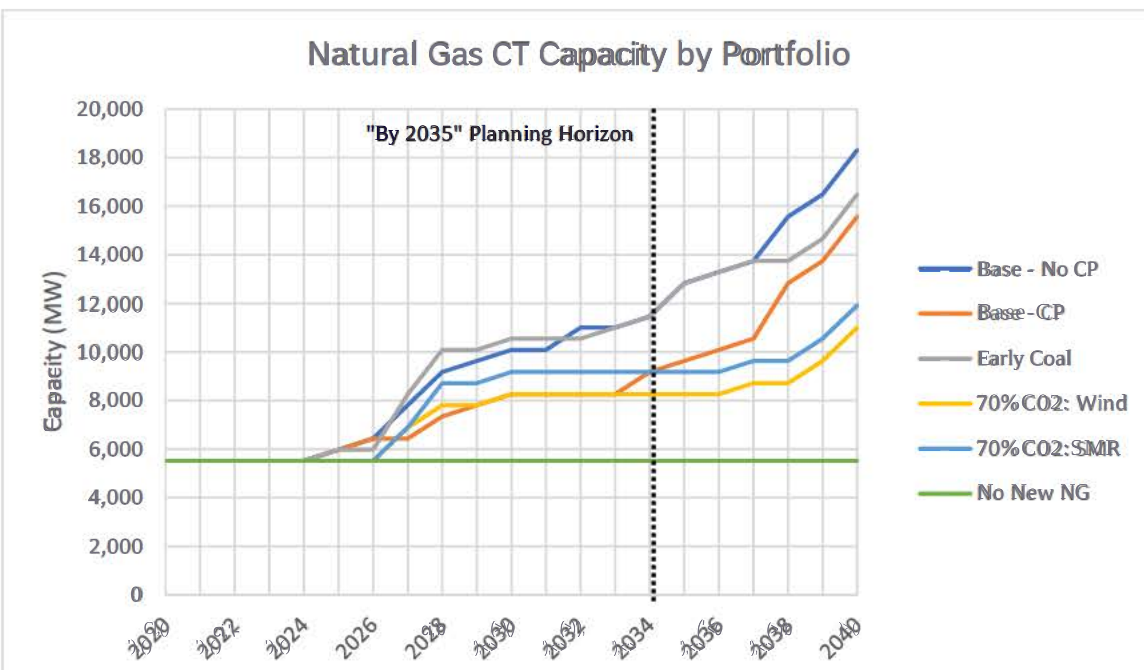

Figure 2 - Natural Gas CT Additions by Scenario

Q27. WHAT TYPES OF RISK ANALYSIS DID DUKE PERFORM WITH RESPECT TO ADDING THIS MUCH NEW NATURAL GAS CAPACITY?

A27. It did very little risk analysis. Duke did include a low and high natural gas fuel cost forecast sensitivity,[40] but it simply assumes that firm capacity to deliver this gas to all its new CC units will be available from "new or upgraded capacity" at a constant price.[41] Given the recent cancellation of the Atlantic Coast Pipeline, the recent $1.2 billion write down by NextEra on its Mountain Valley natural gas pipeline project, and the increasingly challenging siting and permitting environment for new or upgraded capacity, this assumption is not without risk.[42] Further, the Company does not plan on contracting for firm natural gas delivery for its CT units, despite adding nearly 6 GW by 2035 and up to 12.8 GW by 2040 in some scenarios that will be utilized during cold winter mornings and evenings at the exact same time when the natural gas distribution system will be under stress from building heating loads.

Q28. ARE DUKE'S PLANS REGARDING THE ADDITION OF NEW NATURAL GAS UNITS CONSISTENT WITH ITS PLANS TO DECARBONIZE BY 2050?

A28. No, at least not without significant risk of stranding assets or becoming overly dependent on emerging technology. Duke has a corporate goal to have net-zero carbon emission by 2050.[43] This is not the same as emitting zero carbon, as Duke specifically contemplates the deployment of carbon capture and sequestration technology in the future.[44] It also assumes renewable gas and hydrogen will be widely available to power units that previously ran on natural gas and that "zero emission load following resources" ("ZELFRs"), such as SMRs and natural gas combined cycle units ("NGCC") with carbon capture and sequestration ("CCS"), will be commercially available by 2035.[45]

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[40] Which has its own substantial issues, as discussed in Section IV *infra*.

[41] Exhibit KL-4, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-45); Exhibit KL-5, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-55).

[42] In a telling signal, NextEra's announcement of its $1.2 billion write down on its pipeline was coupled with an announcement of adding as much as 30 GW of renewable projects to its portfolio, well above analyst estimates of 20 GW. https://www reuters.com/article/nextera-energy-results/update-1-nextera-energy-posts-loss-on-pipeline-write-down-idUSL4N2K12N3.

[43] https://www.duke-energy.com/Our-Company/Environment/Global-Climate-Change

[44] Duke Energy 2020 Climate Report ("Climate Report") at 4. https://www.duke-energy.com/ /media/pdfs/our-company/climate-report-2020.pdf?la=en. Accessed 1/20/21.

[45] Climate Report at 5.

Q29. ARE THESE TECHNOLOGIES AVAILABLE TODAY?

A29. No, these technologies are not yet commercialized. Although the energy industry will certainly change over the coming 15 years, there is much uncertainty as to whether resources such as SMRs and NGCC with CCS will have been commercialized by that time, or, if they are, if they will be cost effective compared to other technologies. There is also an open question of whether the infrastructure required to sequester the CO_2 captured from NGCC units will be cost-effective or whether Duke's geographic territory has suitable reservoirs. Notably, Duke acknowledges this uncertainty and does not include any CO_2 transport costs outside the fence line, noting these costs are "highly depending on location, as well as the cost of injection."[46]

Renewable natural gas and hydrogen infrastructure to displace natural gas has recently emerged as area of intense interest. It is possible that a new industry will emerge that can supply zero-carbon fuel to Duke's natural gas fleet, but current units cannot burn pure hydrogen without modifications. It is unclear whether Duke will install units that have this capability in the future ahead of widespread deployment of hydrogen as a fuel stock. If they do not, then additional assets will be at risk of stranding or require substantial and costly modifications if and when a switch to hydrogen becomes commercially viable.

Q30. HOW DOES DUKE SEE ITS NATURAL GAS FLEET EVOLVING IN THE FUTURE?

A30. Duke assumes that its natural gas fleet will "shift from providing bulk energy supply to more of a peaking and demand-balancing role."[47] This is consistent with the deployment of large quantities of renewable energy and energy storage that are also required in the net-zero scenarios. However, Duke's Base case portfolios in the IRP double the capacity of high-capacity factor NGCC units by 2040, while other scenarios add between 50% and 75% more NGCC capacity. Much of this capacity is added after 2032, only 18 years before the planned net-zero date.

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[46] Climate Report at 24.
[47] Climate Report at 2.

These units are designed to run at high capacity factors and are not as flexible as combustion turbine units. Building this much new NGCC capacity, with less than two decades until the Company's planned transition to net-zero, risks stranding billions in dollars of assets. While Duke did perform a nominal stranded asset sensitivity, it assumed that natural gas units would have a 25-year life.[48] However, if Duke is serious about reaching net zero in 2050, this assumption appears incorrect for the thousands of MW of new capacity added after 2030.

Q31. ASIDE FROM THE GAS DEPLOYMENT, WHAT OTHER CAPACITY IS REQUIRED IN THE NET-ZERO CARBON SCENARIO?

A31. Duke foresees a massive ramp up in both renewable generation capacity and energy storage. In its illustrative example, the Company projects going from 5 GW of renewables in 2019 to 31 GW in 2040 and 47 GW in 2050. Energy storage increases from 2 GW in 2019 to 7 GW in 2040 and 13 GW in 2050.[49] These deployment levels are not without their challenges, but unlike some of Duke's other resource assumptions, the underlying renewable and energy storage technologies are mature and widely available.

Q32. WHAT STEPS COULD DUKE TAKE NOW TO INCREASE THE LIKELIHOOD OF ATTAINING ITS NET-ZERO GOALS WHILE MINIMIZING THE RISK OF STRANDING NATURAL GAS ASSETS?

A32. The Company should ramp up its deployment of renewable generation and storage in the near term. Duke's 2050 goals call for massive quantities of new renewables and storage over the next 30 years, and yet it backloads much of these capacity additions. The recent passage of the ITC offers a chance to more economically deploy solar and solar plus storage projects prior to 2025 to jumpstart Duke's progress towards its goals.

Q33. PLEASE SUMMARIZE THE RISKS ASSOCIATED WITH DUKE'S SIZABLE NATURAL GAS DEPLOYMENT ASSUMPTIONS.

[48] IRP Report at 137.
[49] Carbon Report at 26.

A33. Duke models huge increases in natural gas capacity, both from NGCC and combustion turbine units. While it presented results primarily through 2035, it modeled scenarios through 2040. The latter build schedules show even more natural gas deployment in the second half of the 2030s, less than two decades before the Company's net-zero pledge. Further, the construction of more natural gas capacity will increase the Company's customers' exposure to natural gas prices. Since Duke is able to pass through fuel costs as an expense, it would be the retail customers who would see higher bills from elevated natural gas prices.

In the near term, Duke assumes firm fuel transport for its NGCC units will be readily available at the same price as today, despite the increasing regulatory risk associated with new pipeline capacity. It does not assume firm fuel delivery for its CTs, despite their increasing usage during winter mornings and evenings when building heating load is highest. These are substantial cost and operational risks that are not well accounted for in the IRP.

Duke assumes substantial technological evolution in its 2050 net-zero goal, which directly informs the 70% CO_2 reduction scenarios in the IRP. NGCC with CCS or broadly-available hydrogen fuel is required to continue to run its turbines. Further, turbines that are designed for hydrogen combustion would need to become the norm and Duke would need to begin to install these well before 2050 lest then-existing assets require major upgrades. The energy sector will certainly evolve in the coming decades, but Duke's decarbonization scenarios rely very heavily on technology with speculative commercial viability.

By contrast, renewable generation and energy storage are mature technologies that can be incorporated earlier and in larger quantities than assumed in Duke's plan. Although the Company's IRP scenarios include sizable renewable buildouts, more could be done earlier in the timeline to reduce reliance on construction of substantial natural gas capacity later in the planning period. This is particularly true given the recent extension of the federal ITC for solar and solar plus storage systems.

E. *A Basic Risk Analysis Shows the Benefit of the Early Coal Retirement Option*

Q34. DID DUKE PERFORM ANY QUANTITATIVE RISK ANALYSES AS PART OF ITS RISK ASSESSMENT?

A34. No. As discussed above, the Company's risk assessments were largely qualitative in nature. It presented the results of its various scenarios and sensitivities but did not produce analyses to compare those portfolios across various input assumptions.

Q35. HOW DID DUKE MODEL CARBON PRICING IN ITS IRP?

A35. Duke modeled a carbon price as a production cost adder in all portfolios except for the Base Case without Carbon Policy. The carbon price commences in 2025 at $5/ton and increases by $5/ton and $7/ton annually in the base and high CO_2 price sensitivities.[50] By 2050, the carbon price has escalated to $130/ton and $180/ton in the base and high case, respectively.

Q36. HOW DOES THIS CARBON PRICE COMPARE TO RECENT CO_2 PRICING ANNOUNCEMENTS?

A36. It is substantially under several alternative proposals that Duke mentions in its IRP, including Energy Innovation and Carbon Dividend Act (H.R. 763) ($15/ton escalating at $10 /ton per year) and the American Opportunity Carbon Free Act of 2019 (S. 1128) ($52/ton escalating at 8.5% per year).[51] It is also substantially under the recently announced carbon price from New York Department of Environmental Conservation, which was calculated at $125 / ton in 2020 before increasing to $373 / ton in 2050.[52]

Q37. DOES DUKE MODEL ANY INCREASED REGULATORY COSTS THAT MAY IMPACT THE ECONOMICS OF CONTINUING TO RUN ITS COAL PLANTS?

A37. No. Duke did not construct a high- or low-cost sensitivity for fuel or fixed O&M costs for coal units, nor did it model retirement outcomes under different regulatory regimes. Given recent developments at the federal level, it is highly likely that new regulations will be enacted that

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[50] DEC IRP Report at 153.
[51] DEC IRP Report at 153.
[52] 2050 carbon price is $178 / ton in $2020. Assuming inflation at 2.5% per year produces a 2050 nominal price of $373.37 / ton. https://www.dec ny.gov/press/122070 html.

substantially change the cost of keeping coal units online, and the risk of such regulations is likely highly asymmetric towards increasing costs rather than reducing them.[53]

Q38. WHAT INFORMATION DID DUKE PROVIDE REGARDING THE PERFORMANCE OF THEIR PORTFOLIOS UNDER DIFFERENT FUEL AND CO_2 COST ASSUMPTIONS?

A38. Duke provided the PVRR values for each scenario, highlighting the base fuel case that excluded the explicit cost of carbon.[54] Under this approach, it appears the Base without Carbon Policy has the lowest PVRR across all sensitivities, with the Base with Carbon Policy and Earliest Practicable Coal Retirement costing about 1% to 6% more and the 70% CO_2 Reduction and No New Gas portfolios costing about 13% to 41% more.

However, these figures do not tell the complete picture, as, with the exception of the Base without Carbon Policy, they do not include the cost of carbon that is modeled in the scenario. When these costs are added back in, the performance of the portfolios changes substantially. After making this change, the Base case Without Carbon Policy does not have the lowest PVRR in 5 of the 6 sensitivities with a carbon price, and the cost premium for the Earliest Practical Retirement portfolio is nearly erased, from an average of 5% without carbon

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[53] President Biden's highly publicized commitment to 100% decarbonization of the electric power sector by 2035 will necessarily require much more stringent regulation of coal-fired power plants than exists today. *See* https://www.washingtonpost.com/climate-environment/2020/07/30/biden-calls-100-percent-clean-electricity-by-2035-heres-how-far-we-have-go/?arc404=true. Moreover, in his January 20 Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden called for the U.S. Environmental Protection Agency ("EPA") to review and consider suspending, revising, or rescinding many Trump Administration actions weakening the regulation of coal-fired power plants, including, but not limited to "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 85 Fed. Reg. 31286 (May 22, 2020). In addition, the D.C. Circuit Court of Appeals recently affirmed EPA's finding that greenhouse gas emissions endanger public health and welfare, and that EPA is thus required by the Clean Air Act to adopt to regulations to address such emissions from new and existing power plants. With respect to existing power plants, that means that EPA must, under 42 U.S.C. § 7411, establish the "best system of emission reduction ["BSER"] that has been adequately demonstrated." The D.C. Circuit rejected the Trump Administration's conclusion – contrary to that of the Obama Administration – that BSER may not include measures beyond the fence line of the power plant, such as mandating the replacement of existing carbon-emitting resources with new zero-emission resources. *American Lung Association et al. v. Environmental Protection Agency et al.*, Case No. 19-1140 (D.C. Cir. Jan. 18, 2021. None of this bodes well for the future of existing coal-fired power plants.

[54] DEC IRP Report at 17.

costs to an average of 1% with carbon costs. Further, the calculated cost premium of the deep decarbonization scenarios fall substantially to 3% to 24% (down from an increase of 13% to 41%), despite Duke's questionable inputs assumptions.[55]

Q39. HAVE YOU PRODUCED ANY ANALYSIS THAT ALLOWS ADDITIONAL COMPARISON OF THE SCENARIOS?

A39. Yes. I ran a cost range and minimax regret analysis on Duke's scenarios that was also performed in the DESC IRP.[56] As in the DESC IRP proceeding, these straight-forward analyses provide insight on how portfolios may perform under a variety of future scenarios. Although fairly simple, they highlight the importance when determining the most reasonable and prudent plan of looking beyond a portfolio that is assumed least-cost in limited scenarios.

Q40. WHAT WAS THE RESULT OF THESE ANALYSES?

A40. When the explicit cost of carbon is considered, the Earliest Practical Retirement portfolio emerges as the most robust of those scenarios that do not specifically target deep decarbonization. Table 2 below shows the cost range and minimax regret analysis for each of the portfolios and the CO_2 and fuel cost sensitivities. Note that these values still contain Duke's flawed natural gas price forecasts, which are substantially lower than fundamentals-based forecasts, and inflated energy storage costs. If the Commission were to require Duke to update its natural gas forecasts, scenarios with higher natural gas usage would be more costly.

[55] Tables 12-B and 12-C, DEP IRP Report and DEC IRP Report.
[56] Direct Testimony of Kenneth Sercy on Behalf of the South Carolina Solar Business Alliance, Inc at 37, Docket NO. 2019-226-E.

PVRR ($b)	Base w/o Carbon	Base w/ Carbon	Earliest Coal	70% CO_2: High Wind	70% CO_2: High SMR	No New NG
High CO_2-High Fuel	116.5	113.7	114.5	122.5	117.3	129.7
High CO_2-Base Fuel	106	104.5	105.3	115.6	110.4	123.1
High CO_2-Low Fuel	99.1	98.4	99.3	110.8	105.6	118.4
Base CO_2-High Fuel	109.6	107.8	108.9	118.5	113.4	125.8
Base CO_2-Base Fuel	99.2	98.8	99.7	111.6	106.5	119.2
Base CO_2-Low Fuel	92.4	92.6	93.7	106.9	101.8	114.6
No CO2-High Fuel	89.2	90.4	93.3	107.4	102.3	114.3
No CO2-Base Fuel	79.8	82.2	84.2	100.5	95.5	108.2
No CO2-Low Fuel	73.3	76.4	78	95.8	90.7	103.5
Cost Range	43.2	37.3	36.5	26.7	26.6	**26.2**
Max Regret	43.2	**40.4**	41.2	49.2	44	56.4

Table 2 - Cost Range and Minimax Analysis – Carbon Cost Included

Q41. PLEASE INTERPRET THE RESULTS OF THIS ANALYSIS.

A41. The Cost Range of each scenario represents the highest PVRR less the lowest PVRR. It is a measure of sensitivity of a scenario to fuel and CO_2 cost inputs. Unsurprisingly, the deep decarbonization scenarios on the right side of the table have the lowest cost range as they contain the least fossil fuel, and thus the lowest exposure to both CO_2 and natural gas prices.[57] The Base without Carbon policy has the highest range of the set, demonstrating the risk of assuming low costs and no CO_2 and finding oneself in a policy world with high fuel costs and high CO_2 costs. Of the three scenarios on the left side, the Earliest Practicable Coal Retirement has the lowest Cost Range result, again showing that eliminating coal earlier while adding more renewables reduces exposure to CO_2 and natural gas costs.

The Max Regret value represents the difference between a portfolio's highest PVRR and the lowest PVRR of all the scenarios. This represents the worst-case outcome of choosing an alternative portfolio compared to selecting the lowest possible portfolio under the least cost option. The low PVRR is established by the Base without Carbon No CO_2-Low Fuel sensitivity at $73.3 billion. Based on this figure, the lowest Max Regret score is from the Base with Carbon, followed closely by the Earliest Practicable Coal Retirement scenario. These have

[57] DEC IRP Report at 8.

Max Regret scores $2.8 and $2.0 billion lower than the Base without Carbon Policy portfolio, suggesting that selecting these two portfolios is less risky than the Base without Carbon Policy.

The Base Case with Carbon has the lowest max regret value at $40.4 billion, followed by the Earliest Practical Coal Retirement at $41.2 billion. The difference between the two amounts to less than 1% of the total PVRR of the portfolios. Importantly, these results do not contemplate new federal or state regulations that may require substantial capital cost investments to maintain the compliance of fossil fuel plants which would be in addition to any variable costs such as fuel and CO_2 that are included. Further, the risk of these new regulations is much higher in the Base cases where coal is assumed to operate longer than the deep decarbonization portfolios when coal plants are retired earlier. This likely understates the cost of owning and operating coal plants compared to baseline included in Duke's IRPs. If this risk were more rigorously quantified, it very well may have an expected value greater than the $0.8 billion noted above.

Q42. DO THE RELATIVELY HIGH MAX REGRET RESULTS FOR THE 70% CO_2 REDUCTION AND NO NEW GAS SCENARIOS CONCERN YOU?

A42. No. Much of the incremental cost of the 70% CO_2: High Wind portfolio over the Earliest Practical Coal Retirement is due to Duke's assumptions of transmission cost. However, the Company has not rigorously analyzed these costs nor considered the cost savings that may come from broader regionalization.[58] Similarly, the No New Natural Gas scenario is hampered by Duke's unreasonable energy storage cost assumptions. Had more reasonable costs been included, the cost of adding standalone storage and solar plus storage would have been reduced and closed the gap between the deep decarbonization portfolios and the others.

Q43. WHAT IS YOUR CLOSING OBSERVATION ABOUT DUKE'S RISK ASSESSMENTS?

A43. Duke failed to present robust, quantitative risk analyses. It focused primarily on the portfolio PVRR under different natural gas and CO_2 cost assumptions but did little to compare the

[58] Exhibit KL-6, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-6).

relative risk of the portfolios against each other. The basic minimax analysis above shows that despite the Base without Carbon Policy scoring the lowest PVRR, it was not the least risky plan. Although the analysis above is hampered by Duke's unreasonable input assumptions, a strong case can be made that the Earliest Practicable Coal Retirements case is the most robust of the non-deep decarbonization portfolios. This result is also supported by the asymmetric likelihood that regulatory costs will rise on coal plants before they fall, further increasing the risk associated with the continued operation of Duke's coal fleet.

III. DUKE'S MODELING ASSUMPTIONS REQUIRE MODIFICATION

Q44. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A44. In this section, I discuss numerous assumptions that Duke made in its IRP modeling. I begin by highlighting the recent extension of the federal ITC and its impact on project economics. I continue to evaluate Duke's cost and operational assumptions for standalone solar, standalone storage, and solar plus storage projects. Finally, I review Duke's development timeframes for the particularly challenging SMR and pumped hydro technologies.

Q45. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A45. The opportunity afforded by the ITC extension should not be bypassed. The two-year extension opens a window where Duke could deploy substantially more solar and solar plus storage projects early in its IRP planning horizon while allowing customers to reap the financial benefits. Although this change occurred after Duke completed its modeling, it is of sufficient scale and consequence that the Commission should direct Duke to update its modeling to incorporate the new law.

Overall, Duke's cost and operation assumptions on solar and storage are mixed. I find that its capital cost assumptions for solar are reasonable (although must be updated to account for the ITC extension), but its fixed O&M cost assumptions do not reflect the technology improvements in that sector. Duke's battery capital costs are substantially overinflated and inconsistent with other benchmarks, in part due to an incorrect interpretation of NREL's ATB forecast methodology. I also take issue with the system mix between fixed-tilt and single-axis trackers and find that Duke's figures are outdated compared to the movement of the market.

Several of Duke's portfolios rely on new SMR and pumped hydro capacity. While acknowledging the challenges of permitting, developing, and constructing these assets, Duke also included documentation that directly contradicts its timeline projections. If Duke is correct on how long these projects will take to develop, it cannot also be correct on when they will be in service.

The impact of these changes in input assumptions and modeling methodologies will likely produce portfolios that retire coal sooner, add less natural gas, and add more solar and storage, particularly early in the planning horizon. Each of these reduces risk of an updated portfolio, reducing substantial regulatory risk associated with the ongoing operation of coal plants and blunting the impact of a potential increase in fossil fuel costs.

A. The Recent ITC Extension Materially Changes Solar and Solar Plus Storage Economics in the Near Term

Q46. WHAT IS THE FEDERAL ITC AND HOW DOES IT IMPACT PROJECT ECONOMICS?

A46. The federal ITC is a tax credit that developers can use to offset a portion of the qualified capital costs of a solar project. It applies to both stand-alone solar projects and solar-plus- storage projects, with the ITC applying to both solar and storage capital costs in the latter. In a typical financing structure, developers will partner with "tax equity" providers that have significant federal tax liability and thus the ability to utilize the tax credits. These tax equity investors will contribute a portion of the up-front cost of the project in exchange for the right to claim the tax credits. This financing method supports the development of assets such as solar PV in which most of the life-cycle costs are incurred up front and that have very low operating costs over the life of the project. The ITC has been a critical driver of solar deployment over the past decade.[59]

Q47. HOW HAS THE ITC LEVEL CHANGED IN RECENT YEARS?

A47. Until recently, the federal ITC was in the process of stepping down. It had been equal to 30% of the eligible project costs for projects commenced in 2019, 26% for 2020, 22% for 2021, and was on schedule to fall to 10% for non-residential projects and 0% for residential projects in 2022 and beyond. To be eligible for any credit in excess of 10% a project also had to be placed in service within four years and also by December 31, 2023. These values were codified in the then-current statute and were thus properly assumed in Duke's IRP modeling completed in summer 2020.

However, Congress passed legislation in December 2020 that extended the stepdown by two years. Now, projects begun by December 31, 2022 will enjoy the 26% credit and those started by December 31, 2023 will receive the 22% credit. Congress also extended the "safe harbor" provisions of the tax credit, which allows developers to "lock in" the ITC for up to four years based on the commencement of construction of the project as long as they are in service by December 31, 2025. This means that a project that begins in December 2022 can lock in the 26% credit as long as it is placed into service before January 1, 2026.[60]

Q48. DOES THIS EXTENSION MAKE A SIZABLE IMPACT ON THE ECONOMICS OF SOLAR PROJECTS?

A48. Yes. The extension of two years is very meaningful. Figure 3 below compares the two schedules showing Duke's assumptions and the current law. The two-year extension provides a relatively modest incremental tax benefit of 4% in 2021, but a much larger 16% and 12% increase in 2022 and 2023, respectively. Further, the drop-dead date for placing a project in

[59] For more information, please see https://www.seia.org/initiatives/solar-investment-tax-credit-itc.
[60] Projects that incur 5% of total costs or have started "physical work of a significant nature" can claim to have "commenced construction" and thus can claim "safe harbor" for the ITC for the entire project cost. For more information, see https://www.seia.org/initiatives/commence-construction-guidance.

service while still being able to safe harbor ITCs higher than 10% has also been pushed back two years. This is critical period in Duke's IRP as it continues to ramp up renewable energy.

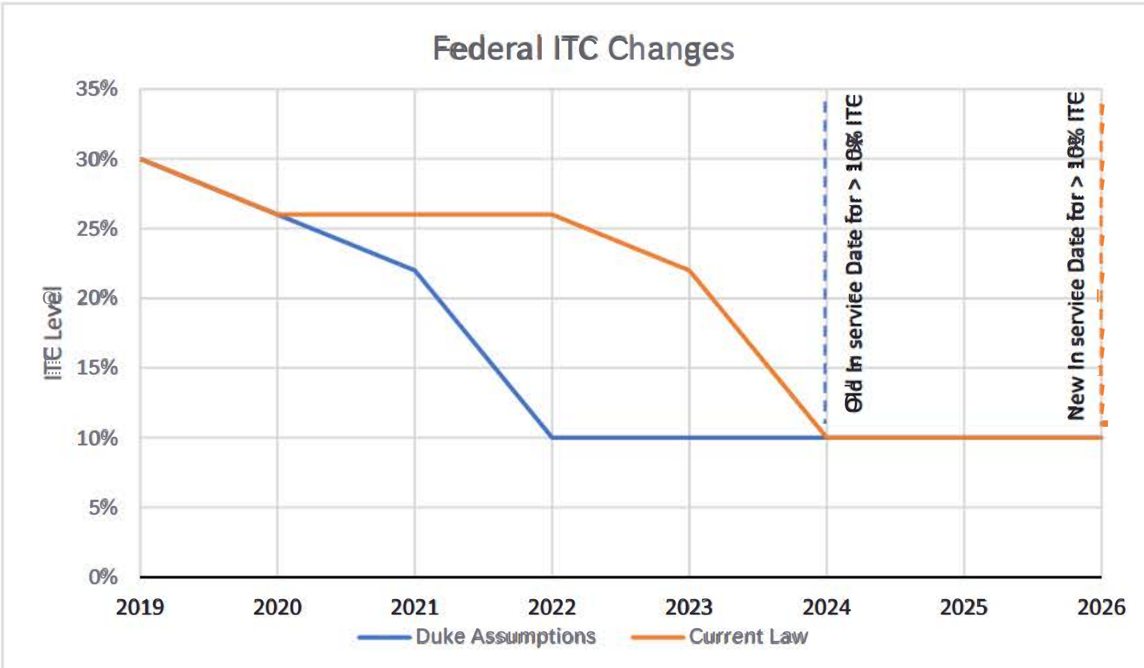

Figure 3 - Federal ITC Changes

Q49. HOW LARGE OF AN IMPACT DOES THE ITC EXTENSION HAVE ON SOLAR ECONOMICS?

A49. Enabling developers to claim a tax credit equal to an incremental 4%, 16%, and 12% of the total capital cost of the project will have a meaningful impact on the economics of new solar and solar plus storage projects. NREL's ATB workpaper calculates the levelized cost of energy ("LCOE") for several locations. While cities in Duke's territories are not specifically modeled, ATB does include data for Kansas City which has similar insolation as Duke's North Carolina and South Carolina territories.

Table 3 below shows the LCOE using NREL ATB's Advanced cost parameters under the old and new ITC paradigm for Kansas City. While neither the production figures nor the financial assumptions are the same as assumptions that Duke or other solar developers would use in South Carolina, the figures serve as a good proxy for the magnitude of impact that the ITC change may have on Duke's modeled results. The percentage reduction in the LCOE of the project is nearly equivalent to the incremental ITC benefit. For projects coming online in 2022 and 2023, there could be a $3-4 / MWh reduction in levelized cost, pushing solar costs into the low-$20s per MWh. This change will make solar even more competitive to new generation, much less with the running costs of existing generation. But capturing these cost reductions will only be possible by increasing solar and solar plus storage deployments in the early portion of Duke's planning horizon.

LCOE ($/MWh)	2020	2021	2022	2023	2024
Duke ITC Assumptions	$24.62	$24.82	$27.07	$25.91	$24.73
Current Law	$24.62	$23.69	$22.74	$22.80	$24.73
$ Delta	$0.00	($1.13)	($4.33)	($3.11)	$0.00
% Delta	0.0%	-4.5%	-16.0%	-12.0%	0.0%

Table 3 - LCOE Under Duke ITC Assumptions and Current Law

Given the four-year safe harbor provisions, it is possible to push out the online date of projects while still capturing a higher ITC level. Developers can capture the higher ITC by ordering adaptable interconnection equipment that it applies to various RFPs. As such, as long as Duke continues with annual RFPs on schedule, developers should be able to lock in the higher ITC for RFPs out to 2023. This would allow equipment placed into service in 2025 while still capturing the higher ITC.

Q50. GIVEN THIS EXTENSION WAS NOT IMPLEMENTED UNTIL AFTER DUKE FILED ITS IRP, HOW DO YOU RECOMMEND PROCEEDING?

A50. Duke was correct to model the existing statute when filing the IRP. However, Act 62 requires the Commission to determine whether a plan was the most reasonable and prudent "as of the time the plan is reviewed."[61] Duke's IRP is still being reviewed, and failing to incorporate the sizable change in law in its modeling would be contrary to Act 62's provisions. I recommend that the Commission direct Duke to update its modeling to reflect the new reality of the federal ITC extension and safe harbor provisions.

[61] S.C. Code Ann. § 58-37-40(C)(2).

B. *Duke's Solar PV Capital Cost Assumptions Must Incorporate the ITC Extension but are Otherwise Reasonable*

Q51. HOW DID DUKE DEVELOP ITS RENEWABLE ENERGY CAPITAL COST ASSUMPTIONS?

A51. Duke relied on capital cost assumptions for offshore wind, solar, and energy storage from Navigant for the years [redacted] through [redacted].[62] For [redacted] forward, Duke escalated costs based on the capital cost increase index from the 2020 EIA AEO.[63] The resulting blended capital cost forecast reflects Carolina-specific factors such as labor costs and land rental while capturing the national-level longer-term cost reduction trends as solar technology evolves.

Q52. HOW DOES DUKE'S FORECAST COMPARE TO NREL ATB'S FORECAST?

A52. Because Duke's forecast utilizes regional-specific data rather than NREL ATB's general nationwide averages, Duke's near-term forecast reflects the lower costs associated with doing business in the Carolinas. Directionally, Duke's forecast represents a downward step of roughly [redacted]% from the NREL ATB Moderate scenario in 2020. Annual cost reductions are shallower than the NREL ATB Advanced scenario from 2020 through 2030, before [redacted] with the ATB Advanced scenario in 2030 and beyond. The resulting forecast is shown in Figure 4 below.

[62] Exhibit KL-3.
[63] DEP IRP Report at 322.

[redacted]

Figure 4 - PV Capital Cost from NREL ATB and Duke

Q53. WHAT IS YOUR VIEW OF THIS FORECAST?

A53. On balance, I believe it is reasonable, although these values must be updated to incorporate the ITC extension. It properly adjusts for local construction and land rent cost factors and shows an overall cost reduction trajectory that, while not as aggressive as the NREL ATB Advanced scenario, does [redacted] the ATB Moderate scenario. I recommend that Duke monitor the evolution of solar capital costs and revisit them frequently as the industry has more often than not seen faster cost reductions than anticipated. If in the future costs are falling faster than currently anticipated, Duke could readily update its forecast.

C. Duke's Solar Fixed O&M Costs are Too High

Q54. WHAT WAS THE VALUE AND SOURCE FOR DUKE'S SOLAR FIXED O&M COSTS?

A54. Duke used a value of $[redacted] / kW-year based on an "[redacted]." This was [redacted] through the analysis period.[64]

Q55. HOW DOES THIS VALUE COMPARE TO THE NREL ATB FIGURES?

[64] Exhibit KL-3.

A55. It is relatively higher than the capital cost forecast, and unlike that metric, Duke does not project a [redacted] in prices over time in the fixed O&M cost category. The NREL ATB Moderate and Advance cases have fixed O&M costs for 2020 of $16.65 and $16.48 / kW-year, respectively, falling steadily to $15.24 and $14.11/ kW-year, respectively, in 2025. Duke's 2020 figure is roughly [redacted]% lower than NREL ATB's, a notable divergence from its capital cost adjustment. By 2025, Duke's figure [redacted] while the NREL ATB has fallen 8.5% and 14.5% even after accounting for inflation.

Figure 5 below shows the original and adjusted NREL ATB values along with Duke's forecast. The adjustment applies the same average [redacted]% discount to the fixed O&M costs as was projected on the capital costs. By comparison, Duke's projection for fixed O&M begins and stays too high.

[redacted]

Figure 5 - Fixed O&M

Q56. ARE THERE INCENTIVES FOR THE SOLAR INDUSTRY TO DRIVE REDUCTIONS IN FIXED O&M COSTS?

A56. Absolutely. As capital costs fall, fixed O&M costs become a higher proportion of the lifecycle costs of a solar plant. Solar is a competitive industry seeking to apply new technologies and data analytics to proactively and predictively anticipate outages to minimize system downtime. Companies that can bid lower cost O&M costs will be able to win competitive procurements, and penalty provisions in PPA documents ensure that operators will hold up their end of the bargain lest face financial penalties. The NREL ATB forecast recognizes these factors and price in a decline over time.

Q57. WHAT DO YOU RECOMMEND WITH REGARDS TO DUKE'S FIXED O&M COSTS?

A57. I recommend that Duke model lower costs to mirror the discount from the NREL ATB that is used in the Company's capital cost forecast. I further recommend that it assume a price decline at least as aggressive as the NREL ATB Moderate scenario to reflect the innovation occurring the in O&M space.

D. Duke's Energy Storage Cost and Operational Assumptions are Inappropriate

Q58. HOW DID DUKE CONSTRUCT ITS ENERGY STORAGE COSTS?

A58. Duke relied on a third-party to produce its energy storage cost estimate rather than relying on one of several publicly available benchmarks. The Company admits that its prices "appear higher than published numbers" but claims this is due to differing assumptions.[65] Specifically, Duke claims that its higher prices are impacted by:

- Using a 20% depth of discharge ("DoD") limit
- Historic DEC/DEP interconnection costs
- Higher software and control costs
- More expensive HVAC and fire suppression equipment
- High integration costs due to the Company's lack of experience with energy storage[66]

[65] DEC IRP Report at 341.
[66] DEC IRP Report Appendix H.

Despite calculating higher initial prices than other benchmarks, Duke does forecast a 34% price decrease between 2020 and 2029.[67] However, other benchmarks also project steep cost declines and thus Duke's costs continue to be above other estimates through 2029.

Q59. How does Duke's topline battery cost estimate compare to other benchmarks or RFP results?

A59. Duke claims that a standalone [redacted] MW / [redacted] MWh battery connected at the transmission level and online in 2021 would cost $[redacted] / kW.[68] This figure is compared to other benchmarks in Table 4 below.

	Capital Cost ($/kW)			Fixed O&M ($/kW-year)		
Online Date	2021	2025	2029	2021	2025	2029
Duke	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NREL ATB Advance	$1,204	$926	$800	$30.10	$23.16	$20.00
NREL ATB Moderate	$1,469	$1,194	$1,121	$36.74	$29.84	$28.03
Lazard v 5.0 (2019)[69]	$898 - $1,874 (2019)					
Lazard v 6.0 (2020)[70]	$752 - $1,401 (2020)					
Santee Cooper RFI	$1,324 (2022)					

Table 4 - Energy Storage Cost Comparison

Q60. Duke claims that other benchmarks "likely only calculate the cost of the battery based on the rated energy of the battery" rather than adjusting for DoD and degradation. Is this accurate?

A60. No. Duke stated that "NREL benchmarked costs against publicly available 3rd party data. If another source did not includes [sic] costs for DoD, NREL did not add additional costs in their benchmarking."[71] While it is true that NREL noted "a number of challenges inherent in

[67] DEC IRP Report at 341.
[68] Exhibit KL-3.
[69] Lazard's Levelized Cost of Storage Analysis – Version 5.0. November 2019. Available at https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.
[70] Lazard's Levelized Cost of Storage Analysis – Version 6.0. November 2020. Available at https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf.
[71] Exhibit KL-7, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-14, attachment NCSEA DR 3-14_BatteryCostComparison).

developing cost and performance projections based on published values", its methodology insulates the final cost projection from this issue:[72]

> To develop cost projections, storage costs were normalized to their 2019 value such that each projection started with a value of 1 in 2019. We chose to use normalized costs rather than absolute costs because systems were not always clearly defined in the publications. For example, it is not clear if a system is more expensive because it is more efficient and has a longer lifetime, or if the authors simply anticipate higher system costs. With the normalized method, many of the difference [sic] matter to a lesser degree. Additionally, as will be shown in the results section, the 2019 benchmark cost that we have chosen for our current cost of storage is lower than nearly all the 2019 costs for projections published in 2017. By using normalized costs, we can more easily use these 2017 projections to inform cost reductions from our lower initial point.[73]

NREL's approach uses third-party data to develop an average cost decline over time and applies that to a benchmark 2019 price of $380 / kWh to create its projections.[74] As long as the individual studies in the third-party data maintained internally consistent assumptions (an entirely reasonable assumption), the specific DoD and degradation assumptions of the individual research reports are less important.

Duke is correct that Lazard's 2019 energy storage report assumed 100% DoD and did not account for degradation. However, Lazard's 2020 energy storage analysis corrected these issues, assuming a 90% DoD assumption and oversizing batteries by 10% to allow for degradation over time.[75] These results produced the more robust results shown in Table 4 above.

Q61. HOW DOES DUKE ACCOUNT FOR BATTERY DEGRADATION OVER TIME?

A61. Batteries degrade with usage. To maintain a minimum performance threshold, one can either oversize the battery at the beginning or augment the battery capacity over time to counteract the degradation. In the overbuild approach, one may install 120 MWh of battery packs in a battery rated at 100 MWh. This would allow for 20 MWh of degradation over the lifetime and

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[72] Cost Projections for Utility-Scale Battery Storage: 2020 Update, NREL June 2020. ("NREL 2020 Update") Available at https://www nrel.gov/docs/fy20osti/75385.pdf
[73] *Id.* at 3.
[74] NREL 2020 Update at 5.
[75] Lazard v6.0 at 4.

still enable the battery to charge and discharge 100 MWh. Under an augmentation strategy, one would install a 102 MWh battery and add roughly 2 MWh of new capacity each year to counteract the degradation of the original capacity. This would also allow the battery to charge and discharge 100 MWh through the life of the project.

Duke approaches this issue differently for standalone storage and for solar plus storage installations. For standalone storage, Duke utilizes an annual replenishment strategy.[76] The annual replenishment cost for the standalone storage is in addition to (and slightly higher than) its annual fixed O&M costs and explains why Duke's estimates are so much higher than NRELs. By contrast, NREL allocates all operating costs to the fixed O&M bucket and uses the higher of the fixed O&M estimates from third parties, thus "in essence assum[ing] that battery performance has been guaranteed over the lifetime, such that operating the battery does not incur any costs to the battery operator."[77] It is unclear why Duke has total fixed O&M costs so much higher than NREL's given that NREL's costs already include everything required for turnkey operation of the project, including the impacts of degradation.

For solar plus storage installations, Duke assumes the lifetime of the battery is equal to the [redacted]-year life of the solar asset, [redacted] the initial battery, and makes [redacted] The [redacted] is substantial. For a [redacted] MW solar PV, [redacted] MW / [redacted] MWh ("usable") battery configuration with a 20% DoD limitation, Duke first assumes that [redacted] MWh of storage is required for [redacted] MWh of "usable" storage. Then, to account for degradation, Duke further assumes a [redacted] ratio to allow the battery to [redacted] for [redacted] years at roughly [redacted] before being overhauled. It also assumes a very high ILR of [redacted], adding further to the total costs of the project.[79]

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[76] DEC IRP Report at 340.
[77] NREL 2020 Update at 10.
[78] Exhibit KL-8, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 5-2).
[79] Exhibit KL-3.

Q62. IS DUKE'S APPROACH TO BATTERY DEGRADATION IN SOLAR PLUS STORAGE PROJECTS LIKELY TO BE A LEAST-COST APPROACH?

A62. No. Energy storage costs are declining rapidly, a fact that Duke itself readily admits and assumes. Under this case, it is inexplicable that Duke would [redacted] its solar plus storage batteries upfront by a total of [redacted]% ([redacted] MWh for an [redacted] MWh "usable" battery) at today's higher costs. The much more rational approach would be to replace energy storage packs as needed on an annual basis to capture the benefit of the cost declines, as it did in its standalone storage approach and as is done in NREL ATB.

Failing to do so greatly exaggerates the cost of storage within the solar plus storage project. This can be seen by comparing the projected cost of two [redacted] MW / [redacted] MWh standalone batteries to the cost of the [redacted] MW / [redacted] MWh storage asset in the solar plus storage project. The 2020 total cost for the standalone battery project is $[redacted] million, but the corresponding total cost of battery portion of the solar plus storage project is $[redacted] million, more than [redacted] higher. This cost differential was explained by Duke to be related to the choice [redacted]

Q63. ASIDE FROM THE IRRATIONALITY OF THIS APPROACH, DOES DUKE'S CALCULATION OF THE [redacted] COST HAVE FLAWS?

A63. Yes. In its calculation for the levelized fixed cost of [redacted] through the [redacted]-year life, Duke's calculation erroneously assumes that [redacted]% of the battery pack must be replaced. Its formula further assumes the incorrect date for the [redacted]. In the calculation for a 2020 solar plus storage battery replacement (due to be done in [redacted] for a system installed in 2020), Duke calculates the cost of replacing [redacted]% of the battery pack, [redacted]% of the power electrics, [redacted]% of the system integration cost, and [redacted]% of the site installation costs. However, these costs are taken from [redacted], not [redacted], shorting the expected cost reduction for the replacement capacity by [redacted] years.

Further, the calculation assumes that 100% of the battery must be replaced. Recall that Duke had overbuilt an [redacted] MWh "usable" battery to [redacted] MWh to account for DoD, and then further overbuild by [redacted]% to [redacted] MWh to allow for degradation. After [redacted] years of degradation, the battery should still be providing [redacted] MWh of capacity. For Duke to [redacted] this battery at zero residual value, despite its sizable remaining capacity, is inconsistent with its own assumptions. At a minimum, Duke should account for some residual value from this battery. More appropriately, it should only replace the [redacted] MWh of overbuild needed to return the battery to the original overinflated capacity with some allowance for incremental capacity to account for the higher likelihood of battery failure past year [redacted]. If the Commission allows Duke to use this approach, it should at least require it to use the proper year for the replacement capacity calculation and require some level of credit for the residual value of the battery.

Q64. ARE THERE OTHER INCONSISTENCIES BETWEEN DUKE'S ENERGY STORAGE ASSUMPTIONS FOR STANDALONE STORAGE AND SOLAR PLUS STORAGE PROJECTS?

A64. Yes. Duke appears to be using a different capital cost estimate for its battery packs in a solar plus storage projects than in a standalone storage projects. For standalone storage projects, battery packs in 2020 are projected to cost $[redacted] / kWh of storage. This value is consistent across all sizes and durations of standalone projects. However, for the [redacted] MW / [redacted] MWh solar plus storage project, the battery pack is assumed to cost $[redacted] / kWh if measured on a "usable" basis (i.e. [redacted] MWh), $[redacted] / kWh if measured after a DoD adjustment (i.e. [redacted] MWh), or $[redacted] / kWh if based on the actual storage amount installed (i.e. [redacted] MWh).

Considering that Duke plans to initially install the [redacted] MWh battery for this project, it appears the lowest cost estimate is the most appropriate. However, that begs the question as to why the battery pack cost would be so much lower in this configuration than for a standalone storage project, particularly considering the degradation strategies and other costs such as power electronics are independent from this cost. Duke's internally inconsistent projections, all of which have been marked confidential, lend further weight to using a publicly available benchmark such as NREL's ATB.

Q65. WHAT DO YOU RECOMMEND WITH REGARD TO BATTERY STORAGE COSTS?

A65. Duke's cost estimates are substantially higher than other benchmarks and recent RFI results. While Duke claims the difference is largely due to assumptions on DoD and replenishment approaches, it erred in interpreting NREL's ATB battery cost methodology. Further, the Commission already ruled on this issue in the DESC IRP case, finding that DESC similarly overinflated its storage costs and directed it to remodel its IRP using NREL ATB's Advanced scenario.[80] I recommend the Commission find similarly in this case and require that Duke base its battery costs on NREL's ATB Advanced scenario, recognize that battery pack degradation is already accounted for in NREL's ATB fixed O&M cost and should not be used to artificially inflate the size of a modeled battery, and require Duke to use consistent costs for batteries in standalone storage and solar plus storage projects unless it can justify differential in cost due to operational expectations.

Q66. WHAT ASSUMPTIONS DID DUKE USE FOR STORAGE DURATION IN ITS ELCC MODELING?

A66. Duke modeled energy storage at two-, four-, and six-hour durations in its 2020 ELCC Study.[81] However, it decided to model only four- and six-hour duration batteries in its IRP, stating that "[t]wo-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak."[82]

Q67. DO TWO-HOUR BATTERIES PROVIDE USEFUL CAPACITY DURING WINTER AND SUMMER PEAK LOAD HOURS?

[80] DESC IRP Order at 50.
[81] DEC IRP Report at 345.
[82] DEC IRP Report at 349.

A67. Yes, they do. Duke included several analyses that show that while two-hour batteries tend to produce lower capacity contribution levels than 4- or 6-hour batteries, they can contribute significantly to winter and summer peak loads. Figure 6 below is the ELCC curve of various battery sizes for DEC and DEP.[83] The two-hour battery (in blue) is somewhat lower than the four-hour (orange) and six-hour (green) lines, but it maintains more than 85% of its capacity value up to about 1,100 MW and 70% of its capacity value up to about 2,500 MW of storage.

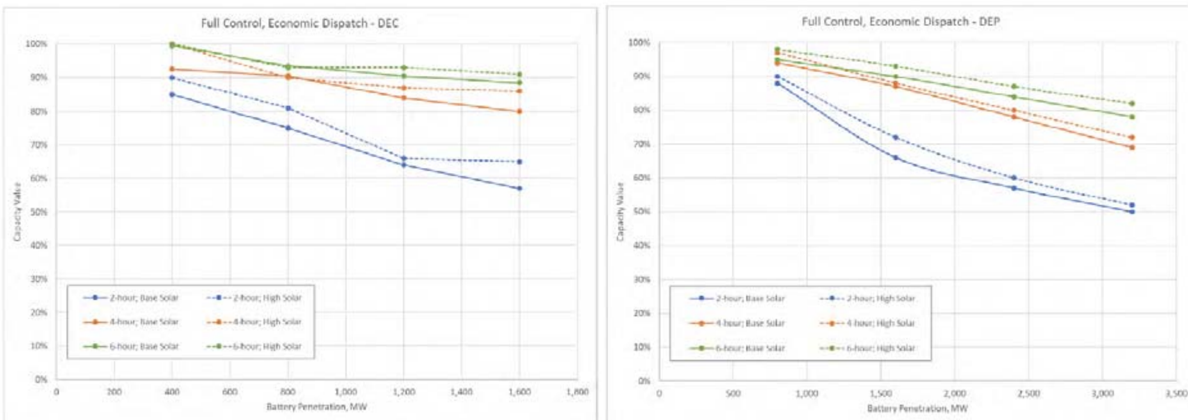

Figure 6 - DEP and DEP Battery ELCC

Considering that battery packs represent a substantial share of an energy storage system's cost, allowing a limited quantity of less expensive two-hour batteries can help defer the need for other capacity at a lower price.

Q68. WHAT IS YOUR RESPONSE TO DUKE'S CLAIM THAT TWO -HOUR BATTERIES "GENERALLY PERFORM THE SAME FUNCTION AS DSM PROGRAMS"?

A68. I disagree. DSM programs typically have limits on how often they can be activated, and even if they did not, participant fatigue could diminish the response after multiple consecutive calls. By contrast, two-hour batteries are independent of business or behavioral decisions and can reliably perform every single day for years on end.

Q69. WHAT DO YOU RECOMMEND REGARDING MODELED BATTERY DURATION?

[83] Figure H-4, DEC IRP Report at 346, DEP IRP Report at 340.

A69. I recommend that Duke update the model to select up to 1,500 MW and up to 1,000 MW of two-hour batteries in DEP and DEC, respectively. These levels correspond to capacity values of 70%. Considering the cost discount that one can obtain from shorter-duration batteries, the tradeoff for capacity value may be selected in the model's optimization routines.

E. Duke's Operational Assumptions for Solar Should be Improved

Q70. WHAT ARE THE TWO MOST COMMON TYPES OF GROUND-MOUNT SOLAR PV PROJECTS INSTALLED TODAY?

A70. The two most common types are fixed-tilt arrays and single-axis tracking arrays. Fixed-tilt arrays feature fixed solar panels that are typically tilted toward the southern horizon. The level of tilt depends on several factors, but typical installations in the Carolinas will have tilts in the 20-30 degree range to increase the total amount of energy produced over the year. Single-axis tracking arrays feature panels that are typically oriented flat in north-south rows that can turn east to west as the day progresses. This tracking enables the panels to face the sun more directly through the day, increasing the amount and duration of energy production.

Q71. WHAT TRENDS EXIST IN THE LARGE-SCALE SOLAR MARKET RELATED TO FIXED-TILT OR TRACKING SYSTEMS?

A71. Over the past decade, there has been a steady shift from fixed-tilt projects to single-axis trackers that has corresponded to a decrease in the price premium of tracking system hardware.[84] Under today's economics, the benefit from added production outweighs the higher cost of tracking hardware, making it an economic decision to install trackers in most locations.

Q72. HAS THIS SAME TREND OCCURRED IN THE CAROLINAS?

A72. Yes, it has. Figure 7 below shows the share of PV systems install by type in North Carolina and South Carolina.[85] There has been a notable increase in tracker deployment since the mid-2010s. More than 80% of PV capacity completed in 2019 used single-axis or dual-axis

[84] EIA Form 860, available at https://www.eia.gov/electricity/data/eia860/.
[85] *Id.*

trackers. Based on conversations with our solar industry members, there is every expectation that this growth trend will continue and that single-axis trackers will be remain the dominant type of system installed in the future.

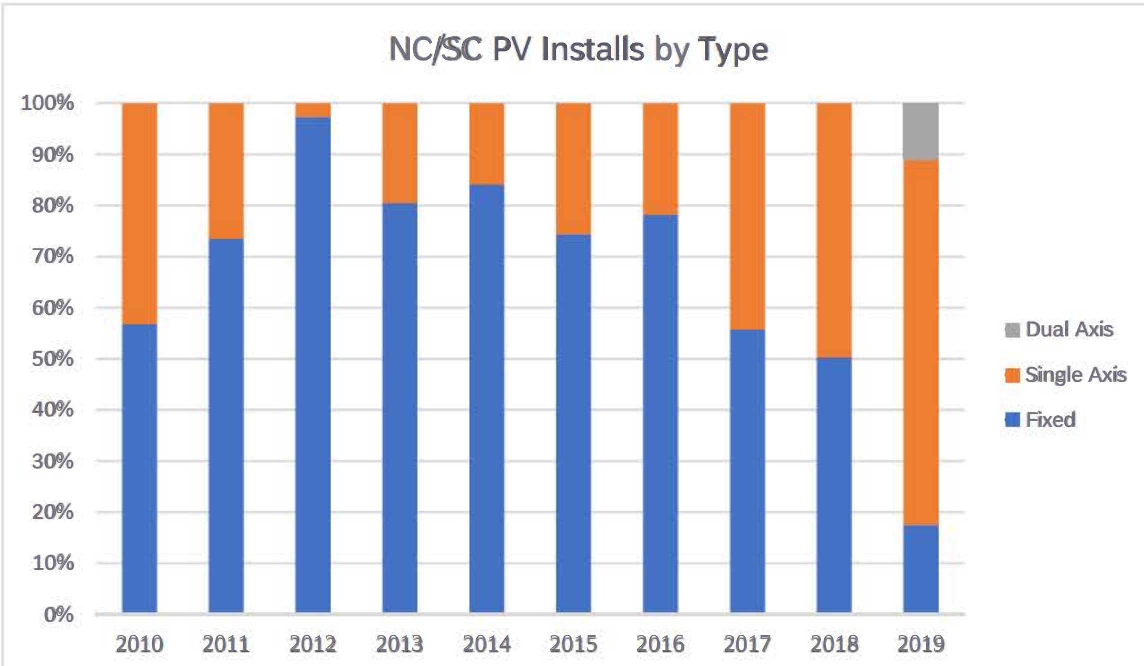

Figure 7 - NC/SC PV Installs by Type

Q73. IS THERE A DIFFERENCE IN SOLAR PRODUCTION FROM FIXED-TILT AND SINGLE-AXIS TRACKING SYSTEMS?

A73. Yes, and the difference is notable. In general, single-axis tracking systems climb to their peak output earlier in the morning and maintain their generation levels later in the afternoon, resulting in a sizable production premium over fixed-tilt systems. Single-axis tracking systems' ability to maintain production later in the afternoon increases the capacity value compared to fixed-tilt installations. Figure 8 below is taken from Astrapé Consulting's "Duke Energy Progress 2020 Resource Adequacy Study" and shows the difference between fixed-tilt and tracking systems at different inverter load rating ("ILR") assumptions.[86,87] The incremental generation in the morning and the evening adds over the year, resulting in tracking systems producing 19% more energy in total than fixed-tilt systems.[88]

Figure 7. Average August Output for Different Inverter Loading Ratios

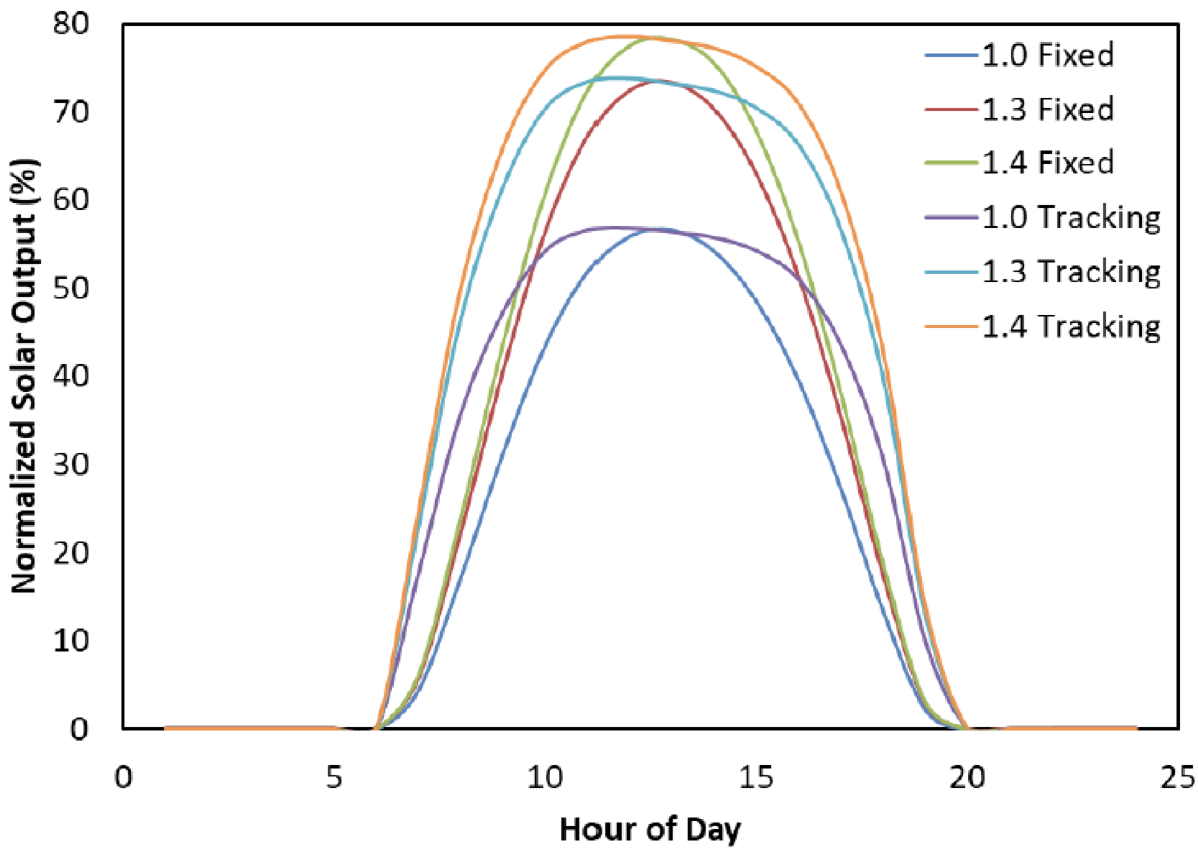

Figure 8 - Fixed vs. Tracking Generation Profile

Q74. PLEASE EXPLAIN HOW DUKE INCORPORATES SOLAR ASSUMPTIONS SUCH AS SYSTEM TYPE AND IRL INTO ITS IRP.

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[86] DEP 2020 Resource Adequacy Study at 35.

[87] The inverter load rating is the ratio of the DC capacity of the panels to the AC capacity of the inverter. While the PV system cannot exceed its AC capacity, increasing the ILR allows the system to produce at its maximum level for more hours, increasing total output.

[88] Exhibit KL-9, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 7-7).

A74. Duke's methodology of incorporating solar in its IRP is anything but straightforward. It relies on a 2018 report from Astrapé Consulting ("2018 Astrapé") to establish the solar-only capacity credit at different levels of penetration.[89] Astrapé modeled different tranches of solar deployment with different system type and ILR assumptions. From this, it estimated the summer and winter capacity credits of 20% and 1%, respectively.[90] These values were used in the IRP modeling for standalone solar projects.

Astrapé assumed 2,950 MW of existing plus "transitional" PV projects in its baseline forecast.[91] Of this nearly 3 GW of capacity, only 297 MW was assumed to be single-axis tracking, with the remainder fixed-tilt. It then added four tranches of capacity in DEP and DEC, assuming 75% was fixed-tilt and 25% single-axis tracking. At the end of its projected deployment, Astrapé assumed that of the 7 GW of solar deployed, only 1,120 MW or 16% would be single-axis trackers as shown in Figure 9 below.

[89] Exhibit KL-10, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-8 ("Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study")).
[90] The "capacity credit" is the fraction of solar nameplate capacity that is assumed to be available to meet summer and winter peak demands. Exhibit KL-10, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-8).
[91] Transitional projects are not defined in the Astrapé study, but appear to be similar to Duke's "designated" capacity.

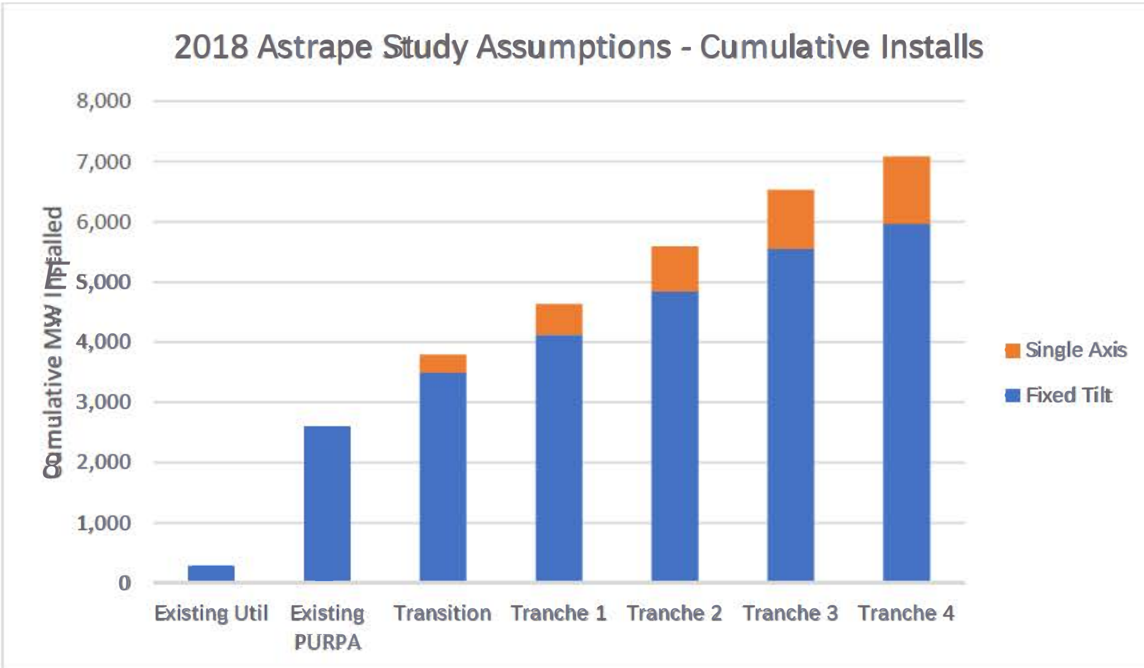

Figure 9 - 2018 Astrapé Study Assumptions - Cumulative Installs

By comparison, 5.2 GW of large-scale solar had been deployed in North Carolina and South Carolina through 2019.[92] At that point, single- and dual-axis trackers already comprised 40% of installed capacity, and based on recent trends, will be projected to increase further in the future. Figure 10 below shows the cumulative installation by type through 2019.

[92] Based on data reported to EIA Form 860 in 2019.

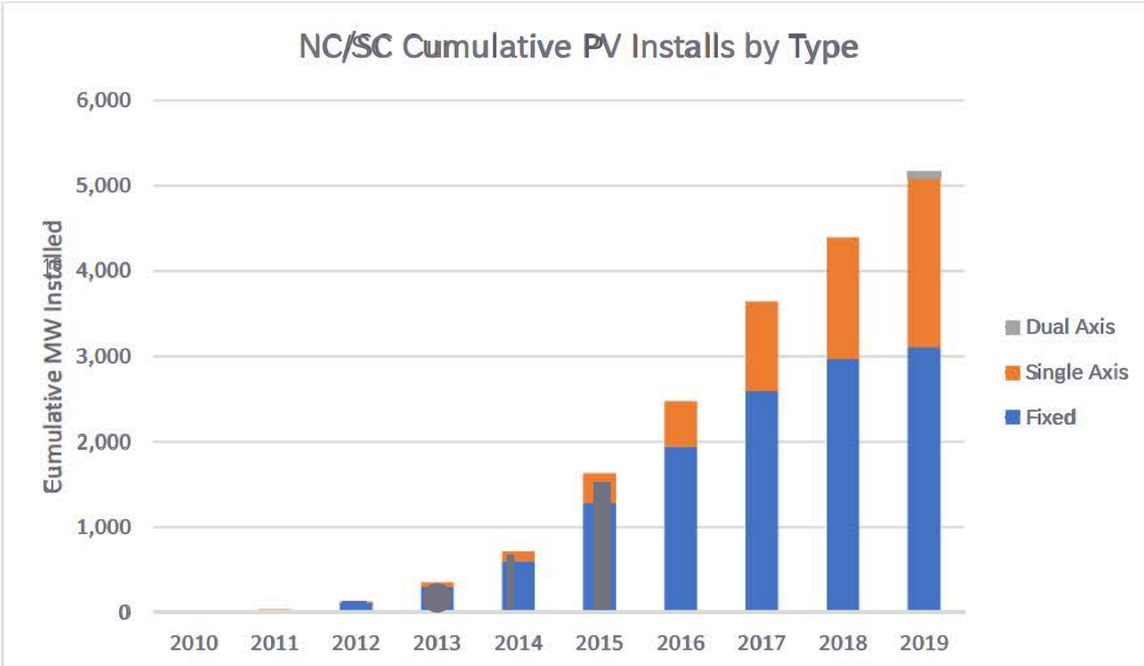

Figure 10 - NC/SC Cumulative PV Installs by Type

Q75. WHY IS THIS DISCREPANCY IMPORTANT?

A75. It is important because by underestimating the share of single-axis trackers, Astrapé is underestimating solar's capacity contribution. Its analysis shows that single-axis tracking systems provide substantially more winter capacity than fixed-tilt systems; tracking systems provided 4-5 times the winter capacity benefit as fixed tilt in DEC's territory, and 8-9 times the capacity benefit in DEP's territory.[93] Although the relative level of solar winter capacity contribution is small under Astrapé's assumptions, when deployed over many thousands of MW, it produces a meaningful difference in the winter capacity contribution of solar-only resources.

Further, because daily generation of single-axis trackers exceeds fixed-tilt systems, solar systems paired with storage will have more opportunity to charge their battery during winter months. This can increase the amount of stored energy that is available to meet both

[93] 2018 Astrapé at 39-41.

morning and evening winter peaks, further increasing the capacity value of solar and storage systems.

Q76. DID DUKE USE THE SAME CAPACITY CONTRIBUTION ASSUMPTIONS FOR ITS STANDALONE SOLAR PROJECTS AS IT DID FOR ITS SOLAR PLUS STORAGE PROJECTS?

A76. No. While the standalone solar capacity contribution came from a 2018 Astrapé Consulting report, the storage and solar plus storage capacity contribution came from a 2020 Astrapé Consulting ELCC study.[94] In this report, Astrapé modeled new solar plus storage systems as single-axis trackers with a 1.5 ILR, but it is unclear what assumptions it used for the existing fleet of standalone solar.[95] The assumption that all new systems be trackers with high ILR is appropriate, but if Astrapé assumed an existing fleet mix that contained too few tracking systems, it could suffer the same underestimate in solar contribution as the 2018 study.

Q77. DOES DUKE USE THE SAME SYSTEM MIX ASSUMPTIONS IN ITS IRP AS IT DOES IN ITS CAPACITY CONTRIBUTION STUDIES?

A77. No. After establishing the capacity contribution of standalone solar from the 2018 Astrapé study, and solar plus storage and standalone storage from the 2020 ELCC study, Duke creates another set of assumptions for the deployment of solar going forward. The Company assumes that 100% of existing PURPA projects are fixed-tilt and will be replaced with fixed-tilt systems.[96] It assumes that development to meet "designated" and "mandated" demand (e.g. builds from existing programs such as CPRE and GSA) will be split 60/40 between single-axis trackers and fixed tilt systems.[97] Finally, Duke assumes future "undesignated" builds will be optimized based on modeling runs.

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[94] *Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study*, Astrapé Consulting, September 2020. ("ELCC Study")
[95] ELCC Study at 7.
[96] Exhibit KL-11, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-5).
[97] Exhibit KL-11.

Q78. WHAT IS THE BASIS FOR THESE FIGURES?

A78. The designation of 100% of PURPA projects as fixed-tilt appear to be based on a simple assumption: "This segment represents the existing capacity associated with standard PURPA contracts which are assumed to be fixed tilt configurations."[98] Duke did not provide any data to support this choice.

The decision to model "designated" and "mandated" system mix was based on the winning bids of the CPRE Tranche 1 RFP, which were received during summer 2018. While these bids may have been reflective of the state of the market at that time, they are no longer reflective of where the industry has moved.

The modeling optimization adds single-axis tracking systems over fixed-tilt systems for all the reasons that were discussed previously.

Q79. ARE DUKE'S ASSUMPTIONS ON THESE ELEMENTS VALID?

A79. No. Duke appears to have blanketly assumed that 100% of PURPA projects are current fixed-tilt and will all be replaced with fixed-tilt systems in the future. This assumption is clearly contradicted by the data. Figure 11 below shows the evolving mix of small systems in the Carolinas that are most likely to have been built under PURPA. While Duke's assumption that all PURPA projects are fixed-tilt may have been more valid through 2016, in the past five years the market has evolved and even these smaller projects are shifting to single-axis trackers. Of the 243 MW of systems under 10 MW built in 2019, a full 80% were single- or dual-axis trackers.

[98] Exhibit KL-11.

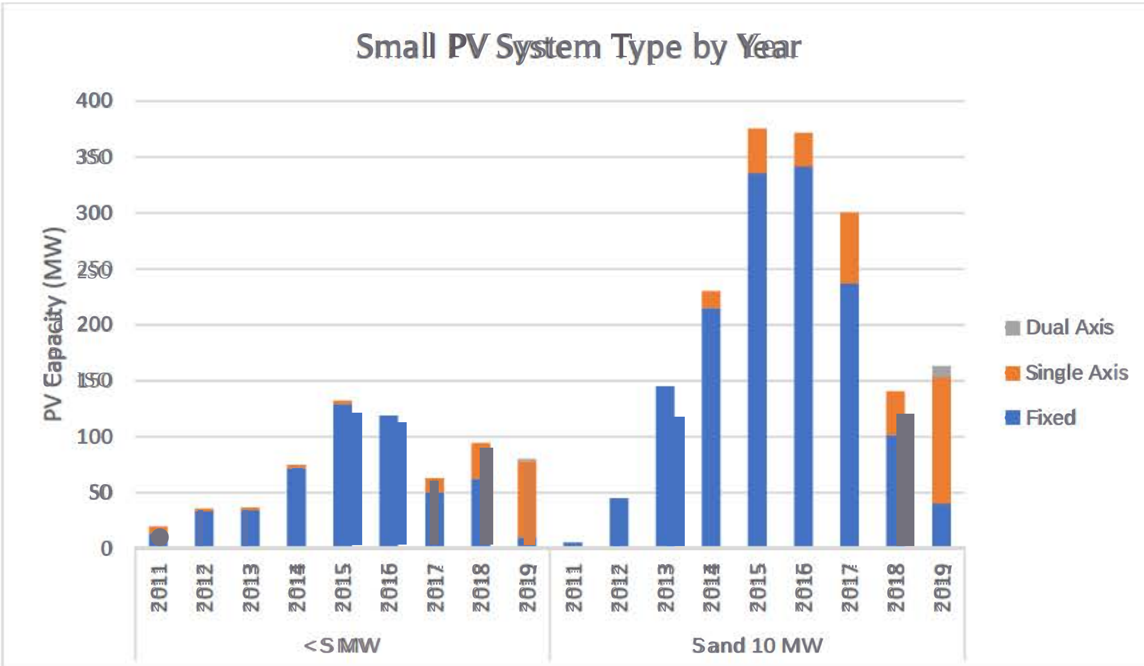

Figure 11 - Small PV System Type by Year

Q80. HAS A SIMILAR EVOLUTION OCCURRED FOR LARGER PROJECTS?

A80. Yes. Figure 12 below shows a similar chart for systems between 20 and 50 MW and over 50 MW. These are the projects that are winning CPRE bids; Duke noted that the median proposal for Tranche 2 RFP was 50 MW in DEC and 75 MW in DEP, with winning bids averaging 55.8 MW in DEC and 80 MW in DEP.[99] Duke's assumption that 40% of these systems will be fixed-tilt is out of date. In 2019, fixed-tilt systems only constituted 15% of capacity in these size categories. Based on trends across the country and in the Carolinas, there can be little expectation that the trend towards tracking systems will be reversed.

[99] Duke IRP Attachment II – Competitive Procurement of Renewable Energy Program Update at 7-8.

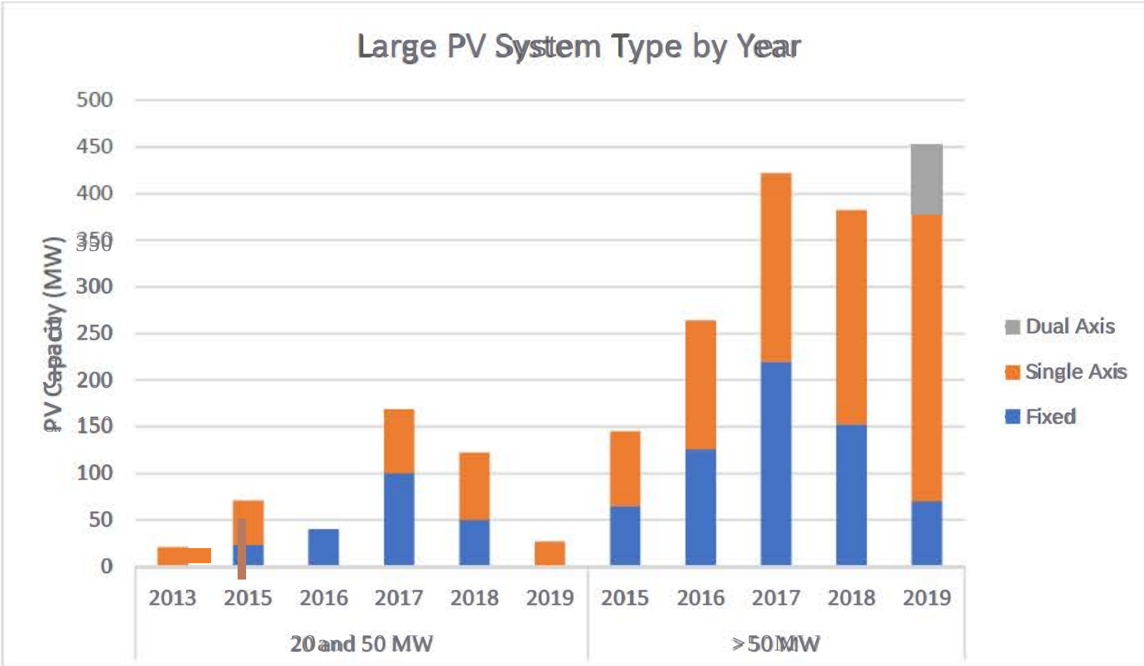

Figure 12 - Large PV System Type by Year

Q81. HOW MUCH CAPACITY IS IMPACTED BY THESE ASSUMPTIONS?

A81. The system type assumptions affect a substantial amount of solar capacity. Figure 13 below shows the breakdown of solar additions by program. The PURPA/NC REPS category (assumed to be 100% fixed-tilt) dominates the early mix, with CPRE capacity additions (assumed to be 60% tracker 40% fixed-tilt) growing through 2026. Only towards the end of 2029 does the future growth category (100% tracker) get deployed in earnest.

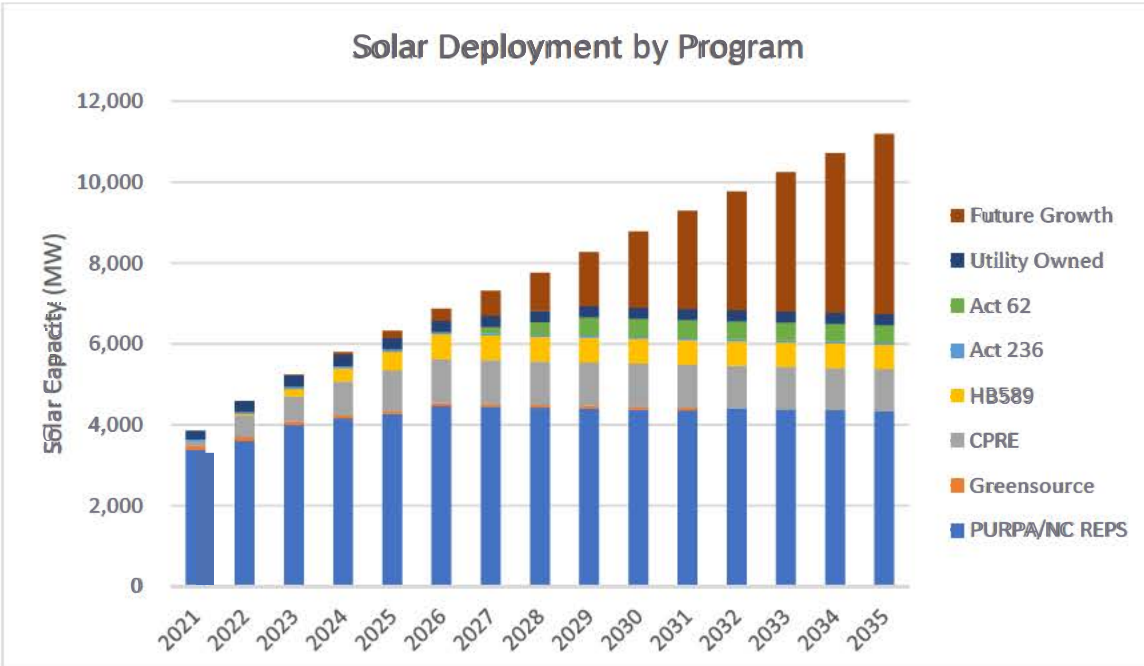

Figure 13 - Solar Deployment by Program

Duke's assumptions on system mix produce a model that relies too heavily on fixed-tilt systems and does not reward the multiple benefits of single-axis tracking systems that are being deployed in the market. This in turn negatively affects the economics of solar and solar plus storage facilities in the Company's modeling.

Q82. WHAT LIMITATIONS DID DUKE ASSUME IN ITS IRP RELATED TO THE INTERCONNECTION OF SOLAR AND SOLAR PLUS STORAGE PROJECTS?

A82. Duke placed a hard limit on the quantity of solar and solar plus storage that could be interconnected in any year to 500 MW (split 300 MW in DEC and 200 MW in DEP) in the base cases and 900 MW (split 500 MW in DEC and 400 MW in DEP) in the high renewable cases.[100] This limit affected all solar, not just those added through the modeling optimization.

Q83. HAS DUKE INTERCONNECTED MORE THAN 500 MW IN ANY YEAR IN IN THE PAST?

[100] Exhibit KL-12, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-18).

A83. Yes. Duke interconnected 718 MW and 744 MW in the two territories in 2015 and 2017, respectively. Its highest single year in DEC was 190 MW in 2016 and its highest year in DEP was 633 MW in 2017.[101]

Q84. WOULD YOU EXPECT DUKE TO BE MORE EFFICIENT AT INTERCONNECTING SYSTEMS NOW AND IN THE FUTURE THAN IT WAS IN 2015-2017?

A84. I would certainly hope so. Duke's IRP scenarios contemplate major build-outs of renewable energy and energy storage. To meet its 2050 net zero goals, the rate must accelerate even further. It is imperative that Duke continue to pursue all options to increase its interconnection capacity for new renewable projects. In addition, Duke's history with interconnection of solar facilities involved large numbers of smaller individual projects. Given the growing trend toward a smaller number of larger projects, Duke's interconnection capability should increase significantly.

Q85. WHAT DO YOU RECOMMEND WITH REGARD TO DUKE'S SOLAR ASSUMPTIONS?

A85. I recommend that Duke update several of its assumptions related to system mix. It is clearly not the case that 100% of PURPA projects are currently, or will be always in the future, fixed-tilt. Duke should perform an analysis on its current PURPA fleet to determine the actual mix of fixed-tilt and single-axis tracking projects and use these in its baseline assumptions. If, for some reason, it is unable to obtain these figures, Duke should utilize the latest data from EIA Form 860. It should further adjust its assumptions on replacement of these projects by recognizing the shift towards tracking that is occurring even at the small system sizes. I recommend an assumption that at least 80% of new PURPA projects be assumed as single-axis tracking based on an extrapolation of 2019 data and that Duke incorporate this into its assumption of replacement capacity from existing PURPA projects.

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[101] Exhibit KL-12, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-18, attachment NCSEA_E-100_Sub165_DR2-18A.xlsx).

For larger systems that are being built to meet Duke's "designated" and "mandated" programs, I recommend Duke assume that 100% of future builds will be single-axis trackers. The cost premium of tracking systems has declined over time, and as shown by the market evolution, the additional energy and capacity benefits that come from trackers more than compensates for the price premium.

I also recommend that Duke remove the 500 MW limit from its base case and instead model the higher 900 MW limit from its high renewables sensitivity. Duke's own plans will require much higher levels of interconnection in the future, making it imperative that the Company pursue changes that will allow higher rates now.

F. Duke's Development Timeline for SMR and Pumped Hydro Resources is Inconsistent with Its Own Data

Q86. WHAT ASSUMPTIONS DOES DUKE HAVE RELATED TO THE AVAILABILITY OF SMRS?

A86. Duke assumes that SMRs will be utilized in two of its six portfolios. The first, "70% CO_2 Reduction: High SMR" assumes that 1,368 MW of SMR capacity will be online by 2029. The second, "No New Natural Gas", assumes 684 MW of SMR capacity will be online by 2035.[102]

Q87. WHAT ASSUMPTIONS DOES DUKE HAVE RELATED TO PUMPED HYDRO?

A87. Duke assumes that a 1,620 MW of new pumped hydro capacity will be online in 2034 in three portfolios: both 70% CO_2 reduction portfolios and the No New Natural Gas portfolio.

Q88. WERE THESE RESOURCES SELECTED AS PART OF THE MODELING OPTIMIZATION PROCESS?

A88. No. These resources were not selected through the modeling optimization process, but rather added manually after the fact in each of these portfolios.[103]

Q89. DID DUKE PROVIDE OTHER INFORMATION RELATED TO THE DEVELOPMENT TIMELINE OF SMR PROJECTS?

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[102] Exhibit KL-13, Duke Response to SCSBA RFP 2 (producing Duke response to DR PSDR 3-14).
[103] Exhibit KL-14, Duke Response to SCSBA RFP 2 (producing Duke response to DR NSCEA 7-3).

A89. Yes. Duke provided this information in response to a question when SMRs are assumed to be online:

> SMRs modeled for the IRP have eight (8) year capital spend, with the first two (2) year [sic] primarily focused around licensing, and the final six (6) year [sic] being construction, testing, and commissioning. As stated in the IRP, the company recognizes the challenges with integrating a first of a kind technology in a relatively compressed timeframe are significant. Therefore, these cases are intended to illustrate the importance of advancing such technologies as part of a blended approach that considers a range of carbon-free technologies to allow deeper carbon reductions.[104]

In other words, Duke would have to begin activities related to SMR deployment this year in order for these units to be online in 2029. Given this case will not be decided until the middle of 2021, and Duke is not requesting approval to build an SMR in its IRP, Duke's own development timelines are incompatible with its assumption that SMR capacity would be online in 2029.

Q90. ARE THERE ANY ACTIVE SMR PROJECTS IN DEVELOPMENT THAT CAN PROVIDE INSIGHT TO THIS CHALLENGE?

A90. Yes. There is a project under development by Nuscale in Idaho that had secured offtake agreements from a number of municipal utilities in Utah. Nuscale spun out of Oregon State University in 2007 and began development of the SMR. The project proposes using twelve 60 MW SMRs to form a single 720 MW facility housed at the Department of Energy's Idaho National Laboratory.

Last fall, after another round of project delays and cost increases pushed the cost estimate from $4.2 billion in 2018 to $6.1 billion in 2020, several of the municipal utilities exited their positions.[105] The project recently received $1.4 billion in financial support from DOE to help keep the eventual price of power from the SMR to under $55/MWh, the maximum amount provided by the agreement with the municipal utilities.[106]

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[104] Exhibit KL-2.
[105] https://www.utilitydive.com/news/design-updates-financial-shakeup-prompt-utilities-to-rethink-structure-of/589262/.
[106] https://www.energy.gov/ne/articles/doe-approves-award-carbon-free-power-project.

Even with this financial support from DOE and having been under development for more than a decade, the facility has not yet received its design certification from the Nuclear Regulatory Commission, although it did pass a key milestone in receiving its safety evaluation report in August 2020. Nonetheless, Nuscale plans to begin construction by December 2025 and have the first module in service by 2029, the same year Duke contemplates a fully-operational SMR facility.[107]

Q91. DID DUKE PROVIDE OTHER INFORMATION RELATED TO THE DEVELOPMENT TIMELINE OF PUMPED HYDRO?

A91. Yes. Duke provided a confidential study performed by [redacted] in [redacted] for [redacted] regarding potential greenfield locations for additional pumped storage located on or about [redacted].[108] This study included cost estimates for [redacted] sites and an environmental, regulatory, and licensing analysis on new pumped hydro. The key details for these projects are shown in Table 5 below.

Project Name	Capacity (MW)	Total Cost [redacted]	Total Cost ($2020)[109]	Cost / kW ($2020)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 5 - Pumped Hydro Study Summary

Q92. WHAT WAS THE DEVELOPMENT SCHEDULE ASSOCIATED WITH THESE FACILITIES?

A92. [redacted] projected a [redacted]-year development timeline for each of the facilities. This included [redacted] years of engineering, environmental, and regulatory studies followed by [redacted] years of

[107] https://www.sciencemag.org/news/2020/11/several-us-utilities-back-out-deal-build-novel-nuclear-power-plant.
[108] Exhibit KL-15, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-36).
[109] Converted using BLS CPI Inflation Calculator, available at https://www.bls.gov/data/inflation_calculator htm.

construction. Based on this schedule, for these units to be online in 2034, development would have to begin in [redacted]. Given this case will not be decided until the middle of 2021, and Duke is not requesting approval to build pumped hydro capacity in its IRP, Duke's own development timelines are incompatible with its assumption that new pumped hydro capacity would be online in 2034.

Q93. WHAT IS YOUR CONCLUSION REGARDING THE INCLUSION OF SMR AND PUMPED HYDRO IN SOME OF DUKE'S PORTFOLIOS?

A93. Based on Duke's own assessments, the timelines projected for SMR and pumped hydro are unattainable. While Duke admits that some of its portfolios are "intended to illustrate the importance of advancing such technologies", it is unfortunate that all three of Duke's deep-decarbonization portfolios rely on resources that, based on Duke's own assumptions, are not likely to be deployed in time to attain the carbon reduction. The Commission should request that Duke construct a deep-decarbonization portfolio that does not require resources with unachievable development timelines, but rather focuses on more robust deployment of existing resources such as solar, wind, and storage.

IV. DUKE'S NATURAL GAS PRICE FORECAST AND SENSITIVITES ARE FLAWED AND BIASED DOWNWARD

Q94. WHY IS THE NATURAL GAS PRICE FORECAST AND YOUR CRITIQUE OF IT SO CRITICAL TO FULLY UNDERSTANDING DUKE'S IRP FILING, ITS PORTFOLIO CONSTRUCTION, AND THE RISK ASSESSMENT OF THOSE PORTFOLIOS?

A94. The natural gas price forecast is one of the most important input assumptions in Duke's modeling. This input impacts how Duke's modeling selects between resources as it optimizes capacity additions across the IRP planning horizon. In the model, Duke enters the IRP planning period with substantial coal capacity and generation, with 18% of capacity and 16% of total generation coming from coal under the Base case with Carbon Policy.[110] By 2035, most of the coal has been retired, and the amount still operating only produces 1% of total generation. How this coal capacity and energy will be replaced is the fundamental question of this case and mirrors the broader evolution of the electricity sector across the country.

Duke's model currently favors natural gas over renewables and storage to replace the retiring coal, as demonstrated by the small amounts added by the model optimization under the two base cases.[111] However, this modeling outcome is not a reflection of the merits of natural gas over renewables, but is instead a mathematical result of the model's assumptions. Further, this mathematical result is heavily influenced by the natural gas price forecast that Duke uses, which is in turn based on low market prices from the illiquid portion of the natural gas futures price curve. By exclusively using ten years of market prices, and relying on those same forecasts for five more years, the model is biased towards building and running natural gas assets. This means that natural gas CC units built in 2027 and 2028 clears out the capacity need for many years to follow, which, under Duke's modeling set up, prevents any more capacity from being built.

But this modeling relies on flawed inputs. A natural gas forecast based more on fundamentals-based forecasts and less on volatile market prices is not only more robust but also presents the model with higher natural gas prices during the critical mid-2020s through mid-2030s period, when the first capacity needs arise. Under this scenario, the economics of building and operating natural gas CCs and CTs will be relatively more expensive than deploying renewables and storage, and the model optimization may reach a very different result that instead is weighted towards zero-carbon renewables and storage.

This has a meaningful impact on the relative riskiness of Duke's portfolios. Duke has already acknowledged the need to transition away from fossil fuels. However, its modeling

[110] DEC IRP Report at 107.

[111] The model does not select any solar in the Base case without Carbon Policy beyond what Duke manually added, and only selects 25% of the total solar in the Base case with Carbon Policy.

assumptions, driven in large part by its natural gas forecast, result in the addition of massive quantities of natural gas generation well into the future. In fact, Duke's Base case with Carbon Policy shows generation from natural gas CCs growing from 21% in 2021 to 31% in 2035, only to be bolstered further by additional CCs past 2035.[112] It has not adequately analyzed the risk associated with firm fuel supply and costs or potential carbon policy in the future, must less reconciled these new gas plants with its 2050 net-zero goal.

Simply put, Duke's flawed natural gas forecast leads to portfolios that are heavily weighted towards natural gas generation instead of ones based more on renewables and storage. If Duke were to follow this path, it would unnecessarily expose its customers and its shareholders to substantial and avoidable risk.

Q95. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A95. For the reasons discussed above, I have developed extensive testimony that walks the reader from Duke's construction of its forecast through the likely final impacts of its choice. I detail Duke's methodology of using market prices for ten years before fully switching to a fundamentals-based forecast by year sixteen in constructing its natural gas forecast and high- and low-price sensitivities. I draw a straight line from the lack of liquidity in the futures market to the lack of robust long-term price formation for the specific financial instrument Duke used to establish the market prices. I also show that long-term futures prices primarily reflect short-term volatility rather than being reflective of the macroeconomic dynamics that influence long-run prices. I then discuss the flaws in Duke's approach to producing its high- and low-price sensitivity, before concluding with observations about the potential collective impact of these choices on Duke's IRP modeling that may have resulted in more natural gas and less solar and storage resources being added in the future.

Q96. WHAT ARE YOUR PRIMARY CONCLUSIONS?

[112] DEC IRP Report at 107.

A96. Duke's natural gas forecast is highly problematic. It begins with a flawed assumption that its ability to purchase *de minimis* quantities of natural gas on ten-year contracts justifies its decision to base the first ten years of its model entirely on market prices. I show how prices from the financial instrument it used to secure the gas supply are directly derived from futures contracts, and how the prices for those futures contracts beyond two years are based on almost no market transactions.

I then show how near-term price volatility in the natural gas futures market works its way into the long-term portion of the futures price curve. As part of this analysis, I show the sizable week-to-week volatility that occurred in 2020 meant that if Duke had locked in its gas forecast a few weeks earlier or a few weeks later, it would have produced a meaningfully different result.

The fact that a key input like the first ten years of natural gas prices is so exposed to short-term volatility is a clear sign that it should not be relied upon for more than a few years. To counter this, I propose an alternative forecast methodology that would smooth the short-term volatility in the market prices and only rely on them exclusively for 18 months before transitioning over 18 months to a fundamentals-based forecast.

Next, I discus the methodology that Duke used to construct its high- and low-price sensitivities. Because the Company's method is entirely based on the short-term price volatility of futures contracts, extrapolating out ten years produces a "random walk" result that deviates substantially from fundamentals-based forecasts. The resulting sensitivities contain disjointed segments that would require a bizarre sequence of massive policy shifts to bring to fruition.

Finally, I discuss how Duke's natural gas price forecast might have impacted its IRP results and why it is critical that the modeling be updated with better assumptions. These forecasts impact asset selection, PVRR, and carbon emissions, and play a key role in the risk assessment that Duke should have produced between its several portfolios. Leaving this many outcomes dependent on a flawed natural gas price forecast is highly inappropriate.

A. Duke's Use of Market Prices for Ten Years is Inappropriate

Q97. HOW WAS DUKE'S NATURAL GAS PRICE FORECAST DEVELOPED?

A97. Duke based its forecast on "market prices" from financial instruments that were prices based on natural gas futures contracts for years 1 through 10, transitioned linearly to a fundamentals-based forecast from years 11 to 15, before utilizing a fundamentals-based forecast from year 16 forward. The Company also developed a high- and low-price sensitivity, applying a statistical methodology to market prices before transitioning to two Energy Information Administration (EIA) Annual Energy Outlook (AEO) fundamentals-based forecast scenarios.[113] The resulting annualized forecast is shown below in Figure 14. This is a recreation of Figure A-2 from the DEC IRP Report and clearly delineates the three disjointed sections of 100% market prices and 100% fundamentals-based forecast, joined by the five-year transition between the two.

[113] DEC IRP Report at 157-158.

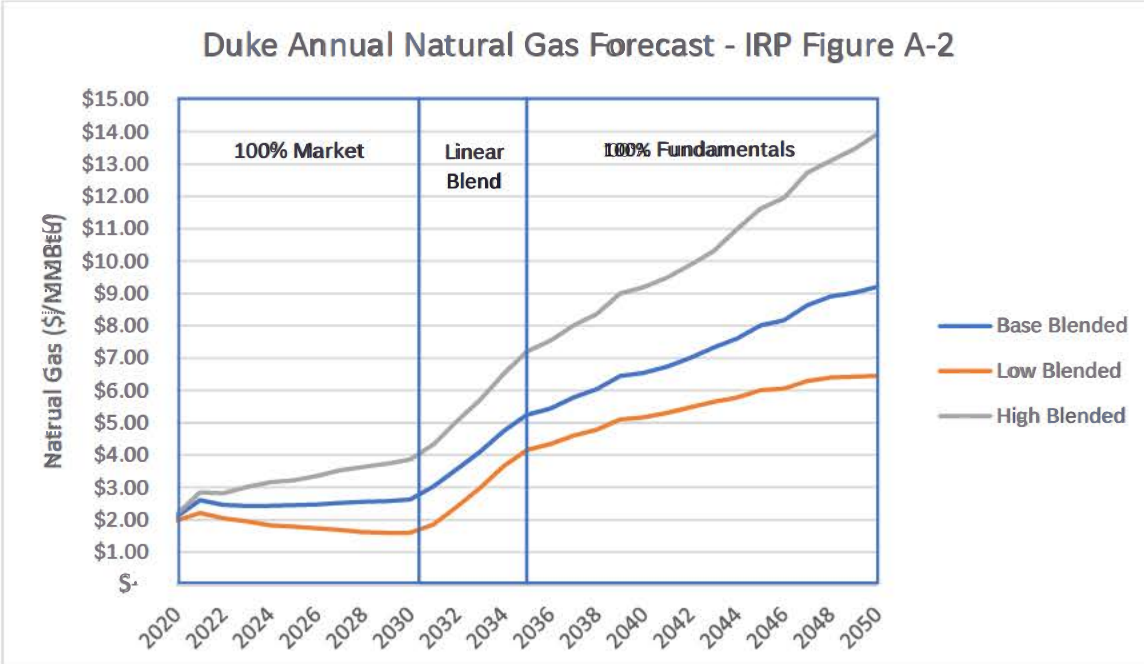

Figure 14 - Duke Annual Natural Gas Forecast - IRP Figure A-2

Q98. WHAT MARKET PRICE DOES DUKE USE IN ITS FORECAST?

A98. Duke uses market prices based on a 116-month fixed price swap for 2,500 dts/day for May 2020 through December 2029.[114] The fixed-price swap (or swap) is a financial derivative that allows market players to hedge their future purchases or sales of a commodity by locking in a fixed price now rather than facing the market price in the future. For a purchaser of natural gas such as Duke, buying a swap allows it to lock in its natural gas fuel price in the future and reduces the risk associated with market price fluctuations. If the market price in the future is higher than the swap price, then Duke will save money, but if it is lower, it will lose money. That said, the point of hedging in general is not to speculate on the future price of natural gas (there are other ways to accomplish that), but to reduce risk of Duke's financials associated with natural gas price fluctuations.

The monthly price of the swap is based on another financial product called a futures contract (also referred to as just futures). These contracts are financial instruments between

[114] Exhibit KL-16, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 5-3).

two parties (a buyer and a seller) that gives the buyer the right to receive and obligates the seller to deliver a certain quantity of natural gas at a certain price at a certain place in the future.[115] For example, one can purchase a futures contract that would give the buyer the right to receive 10,000 MMBtu of natural gas in July 2024 at Henry Hub at $2.433 / MMBtu.[116] If in July 2024 the spot price (i.e. the then-current market price) for natural gas is $3.00 / MMBtu, the holder of the futures contract would have the right to receive it from the seller for $2.433 / MMBtu for gas rather than the higher market price.

Swaps and futures are different but related products. Futures contracts are standardized (same quantity, same delivery location) and settle through the NYMEX exchange and obligate physical delivery or receipt of a product. Swaps, by contrast, can be customized to meet the requirements of the buyer or seller, such as changing the location of delivery, and can be purchased through brokers or through commodities exchanges.

Q99. WHAT IS A FUNDAMENTALS-BASED FORECAST?

A99. A fundamentals-based forecast uses a model that simulates entire sectors of the economy to determine supply, demand, and prices for commodities. The EIA AEO uses the National Energy Modeling Systems ("NEMS") model for this purpose. EIA describes NEMS as

> a computer-based, energy-economy modeling system for the United States. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.[117]

Q100. WHAT IS THE DIFFERENCE BETWEEN PRICES FROM NATURAL GAS FUTURES CONTRACTS AND SWAPS AND THOSE FROM A FUNDAMENTALS-BASED FORECAST?

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[115] Futures rarely result in physical delivery of the product. Instead, holders of the contracts typically close their positions prior to physical delivery.
[116] https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex html.
[117] *The National Energy Modeling System: An Overview 2018*, available at https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2018).pdf.

A100. Much like equities in the stock market, futures prices are affected by market participants buying and selling contracts and by factors such as weather or policy changes that may affect future natural gas supply and demand. Futures prices can be very volatile and reflect the short-run impacts of factors such as weather and natural gas storage capacity. Futures are also used by produces or consumers of natural gas to hedge their planned natural gas sales or purchases and can be traded by anyone simply looking to speculate on expected changes in price. All of these factors, including purchases by companies like Duke and commodities speculators halfway around the world, impact the price of these financial derivatives.

By contrast, a fundamentals-based forecast such as AEO eliminates much of the short-term noise from commodities traders and weather, focusing instead on the underlying factors and policies that drive long-term behavior. AEO contains numerous policy scenarios that determine how prices will respond to, for example, the introduction of a carbon price or federal clean energy legislation, or a sudden increase or decrease in the availability of natural gas or oil at low prices. These changes filter through the entire model, meaning that the supply, demand, and prices that emerge reflect the holistic result of the fundamentals, not short-term trends driven by weather or trading activity.

Q101. HOW ROBUST ARE THE FUTURES MARKET PRICES?

A101. The robustness or "efficiency" of market prices[118] is heavily driven by a market's liquidity; illiquid markets or products that have few trades and low volume are less robust and produce less efficient prices than liquid markets with many participants. The most popular natural gas future is the Henry Hub Natural Gas ("NG") future found on the NYMEX exchange.[119] While there is considerable volatility in the price of these contracts, as the third-largest physical commodity futures contract in the world by volume, it is very liquid – for some time periods.

Q102. WHAT DO YOU MEAN "FOR SOME TIME PERIODS"?

[118] In this context, efficient pricing is one that incorporates sufficient relevant information that allows buyers and sellers to make informed decisions about the value of the assets they are trading.
[119] https://www.cmegroup.com/trading/energy/nymex-natural-gas-futures html#tab1.

A102. Trading exchanges list two metrics of market activity: volume and open interest. Volume reflects the total amount of activity in a day (i.e. the total number of contracts that were bought or sold) while open interest reflects the total number of contracts that are outstanding (i.e. how many open contracts exist between buyers and sellers). The NG future offers monthly prices for the current year and next 12 calendar years, meaning that one can in theory lock in the price for delivery of natural gas between next month and December 2033. However, the overwhelming majority of market activity is constrained to contracts less than a year in the future, and there is almost no market activity for contracts more than two years in the future.

Q103. WHY IS THAT IMPORTANT?

A103. It is important because higher market activity leads to more accurate price formation, and conversely, low market activity leads to poor price formation. Imagine a saleswoman is selling a blue widget and wants to know what its value is to purchasers. If the saleswoman asks only one person what they would pay for it, the answer may be dependent on somewhat random factors such as whether that person liked the color blue or if they already had a widget. If she happened to ask a prospective customer who liked blue, the perceived value of the widget may be higher than if she happened to ask someone who preferred red. But if the saleswomen asks 100 people, or 1,000 people, or 1,000,000 people, more information can be incorporated into the price and the saleswoman will have a much better sense of how much customers will pay for the widget.

Q104. EXACTLY HOW LITTLE MARKET ACTIVITY EXISTS IN NATURAL GAS FUTURES BEYOND TWO YEARS?

A104. The market activity drops substantially as one moves into the future.[120] Figure 15 below shows the cumulative trading volume of all NG futures contracts averaged over the days of January 20, 2021 to February 2, 2021. On those days, 77% of all volume was for futures contracts no

[120] Market activity obtained from CME Group at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex html.

more than six months in the future, 94% for contracts up to a year out, and 99.1% for contracts up to eighteen months out. There was no trading at all for contracts past May 2024.

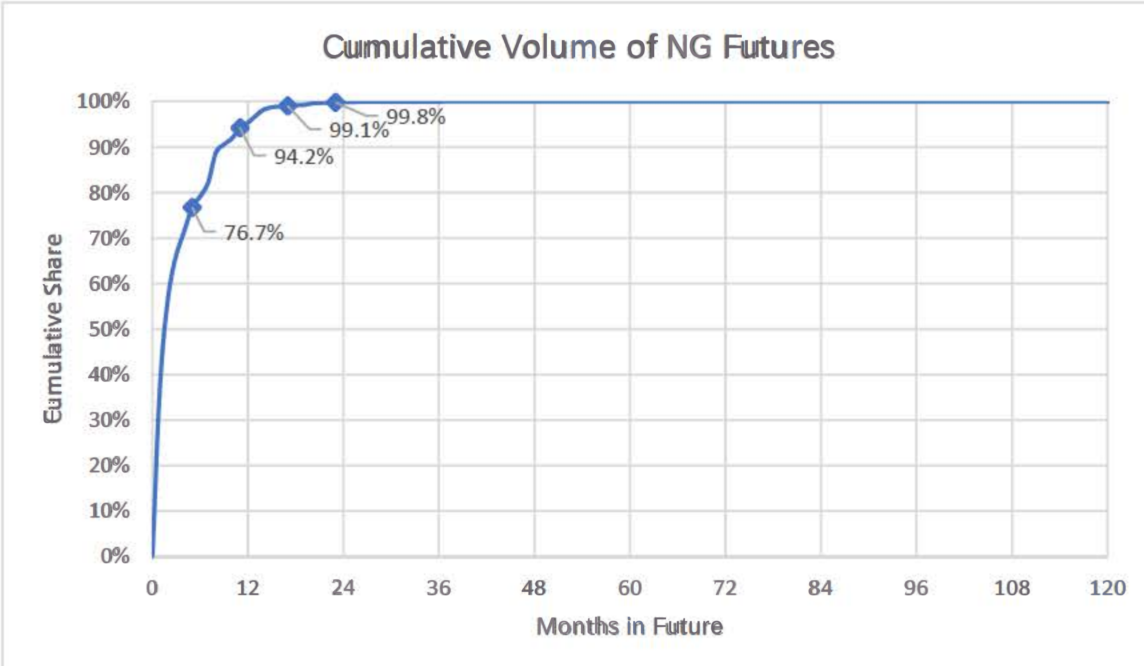

Figure 15 - Cumulative Volume of NG Futures

Figure 16 below shows a similar chart but for open interest. The curve is slightly flatter, with 86.2% of open interest for contracts within one year and 98.1% for contracts within two years. Only 0.083% of all open interest in the most liquid natural gas exchange in the world is for contracts from January 2026 and beyond. To put that in perspective, the number of open contracts in the next 12 months is roughly equal to 85% of the natural gas volume used by the entire U.S. electricity power sector in 2019. By contrast, the total number of open contracts from January 2026 through December 2033 would only be enough to power a single 1,200 MW NGCC plant for two and a half months.[121] This paltry volume does not support robust price formation.

[121] As of closing on 1/28/21, there were 973,194 open contracts of 10,000 MMBtu each for March 2021 through February 2022. This is equal to 9,732 bcf. According to EIA, the U.S. electricity power sector used 11,287 bcf of natural gas in 2019. On that same day, there was a total of 1,317 open contracts for January 2026 through December 2033. In a typical 7,000 heat rate NGCC unit, this would produce 1,881 GWh, the same amount from running the plant for 78 days.

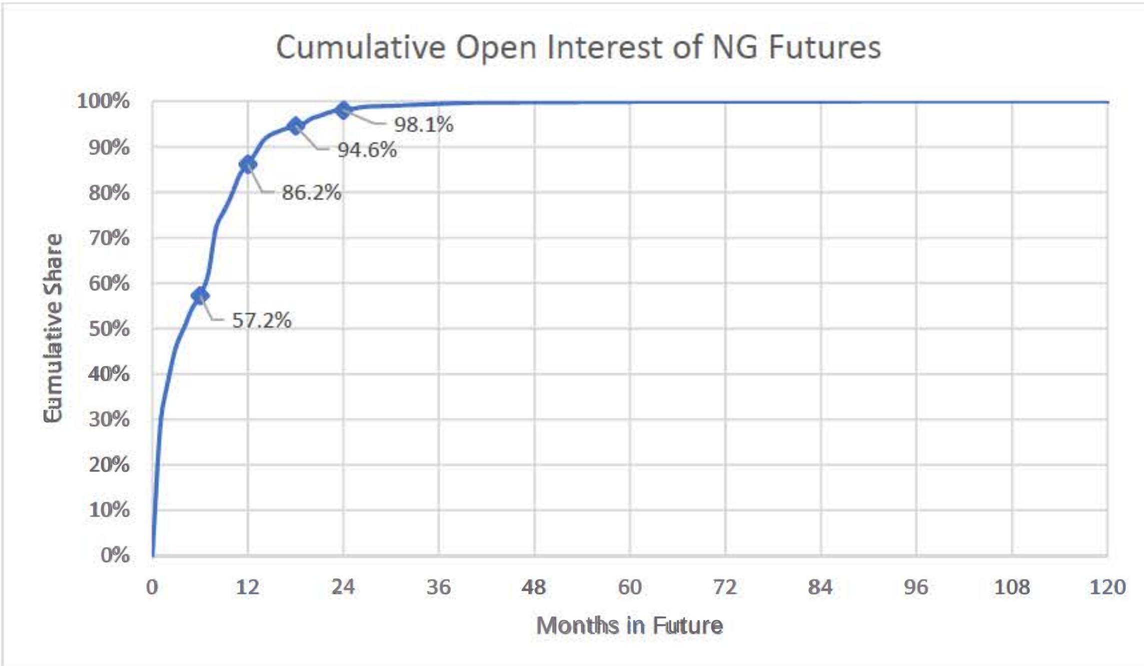

Figure 16 - Cumulative Open Interest of NG Futures

Q105. DOES THIS LACK OF LIQUIDITY IN THE LONG-TERM FUTURES MARKET TRANSLATE INTO SWAPS?

A105. Yes, it does. While swaps are not the same product as futures, they are priced based on futures contracts with potential incremental charges for brokers fees or risk premiums. This relationship is clear when one inspects the price of Duke's swap with the corresponding futures contract from that day, as shown in Figure 17 below. The prices of the two instruments are [redacted], with only a [redacted] in the swap in the out years.

[redacted]

Figure 17 - Duke Swap vs. Future Price

Because of this, the lack of liquidity in the market for futures more than five years out becomes embedded in the price of a swap. So while Duke may be able to procure small amounts of natural gas through 10-year swaps, it does not mean that the prices on which they are based have been robustly set by the market.

Q106. DUKE HAS ARGUED THAT ITS ABILITY TO PURCHASE SMALL AMOUNTS OF GAS ON A TEN-YEAR FORWARD BASIS DEMONSTRATES THE MARKET IS SUFFICIENTLY LIQUID TO RELY ON ITS PRICES.[122] HOW MUCH NATURAL GAS SUPPLY DID DUKE SECURE IN THE SWAP DISCUSSED ABOVE?

A106. It procured 2,500 decatherms/day, equal to 2,500 MMBtu per day. In a natural gas combined cycle unit with a typical heat rate of 7,000, this is sufficient to generate about 357 MWh per day or 130 GWh per year. Considering that DEC and DEP combined have forecasted sales of

[122] See e.g. Reply Comments of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Docket No. E-100, Sub158 at 17. Available at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7c33d58d-fc8e-47ac-8f27-d96222c3ec38.

154,228 GWh in 2020, the natural gas fuel needed to supply 0.08% of Duke's annual generation secured the swap is simply *de minimis*.[123]

If Duke wishes to use market prices for up to ten years in its gas forecast, it should obtain market quotes from reliable brokers for a meaningful quantity of gas to see if they are available and at prices comparable to small purchases. For instance, it would be instructive to see the price to purchase 50% of Duke's projected natural gas consumption from for the next ten years on a fixed price contract. If there is even a counterparty willing to sell this contract, it will likely contain a price premium that makes it substantially more expensive what Duke has demonstrated through relatively tiny purchases.

Q107. DOES DUKE ACTUALLY LIMIT ITS USE OF MARKET PRICES TO TEN YEARS?

A107. No. Despite what Duke claims in its IRP report, it is using market prices to define or influence its natural gas forecast for a full 15 years. Duke relies entirely on market prices for the first 10 years of its forecast. Only after this point does it switch linearly from the market prices to the fundamentals-based forecast. So while the influence of market prices diminishes each year after year 10, it continues to impact the final forecast until year 16.[124]

Q108. DID DUKE OBTAIN MARKET PRICES FOR THIS FULL 15 YEARS?

A108. No, it did not. The market prices from the 10-year swap stop in December 2029. Monthly futures available on April 9, 2020, the date when Duke locked in its natural gas market price forecast and its high- and low-price forecasts, only went through December 2032.[125] To extend these prices to 2035, Duke simply applied the "year-over-year growth from the last year of market data."[126] The complete lack of market data available for prices this far in the future should preclude Duke from applying any weight whatsoever to market prices past twelve years to its natural gas forecast.

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123 2020 IRP_ Model Inputs_NON-CONFIDENTIAL.
124 DEC IRP Report at 157.
125 Exhibit KL-17, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-35).
126 Exhibit KL-17.

B. *Futures Prices are Highly Volatile and Incorporate Short-Term Volatility into Long-Term Prices*

Q109. HOW ARE PRICES IN THE NATURAL GAS MARKET BEST DESCRIBED?

A109. They are best described as highly volatile. The natural gas industry is a sprawling, complex sector of the economy. Natural gas is used not only by the electric sector for electricity generation but used heavily in residential and commercial buildings for space and water heating and by industry as feed stocks for many products. Production, transmission, and storage of natural gas involves an entire other set of market participants, and there is a vibrant commodity market where traders and speculators seek profits on natural gas financial derivatives.

Demand for natural gas is highly dependent on weather and storage capacity, leading to major swings in prices during extreme weather events that affect demand or natural disasters that impact supply. Because the market is affected by myriad factors, many of which are unknowable more than a few days out, daily prices are highly volatile. Figure 18 below shows the daily Henry Hub spot price from 1997 through 2021.[127] Major events such as Hurricane Katrina in 2005, Hurricane Ike in 2008, and the Polar Vortex in 2014 can be clearly seen through their impact on prices.

[127] https://www.eia.gov/dnav/ng/NG_PRI_FUT_S1_D htm.

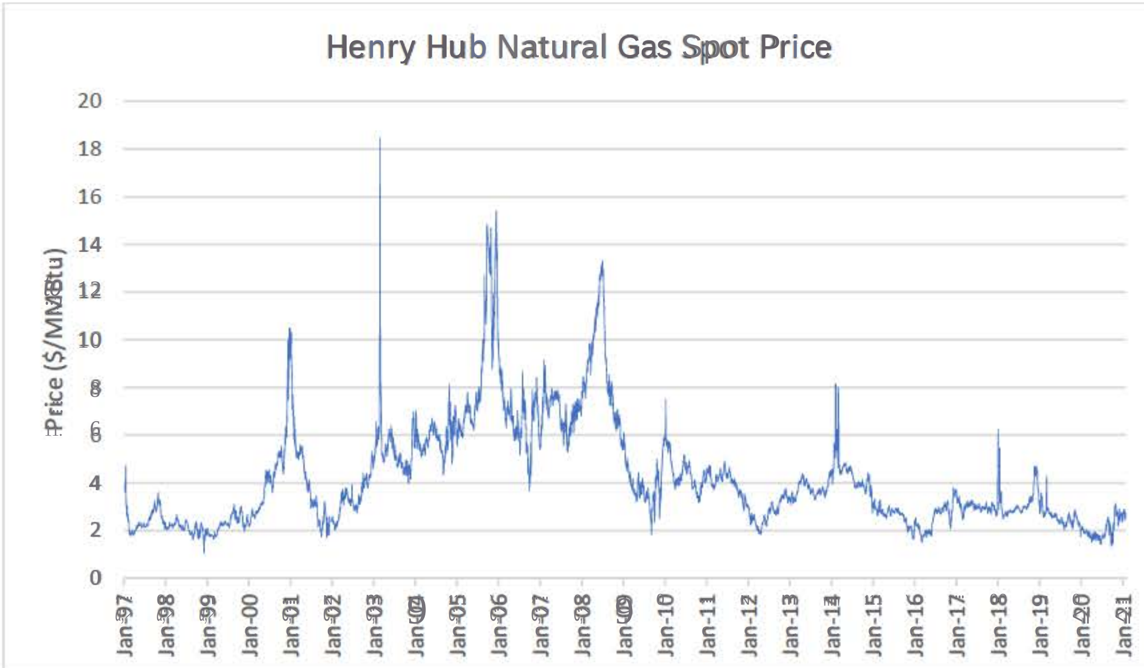

Figure 18 - Henry Hub Natural Gas Spot Price

This volatility in prices and corresponding futures contracts can be analyzed and visualized. EIA maintains a data set of Henry Hub spot prices and corresponding futures contracts for one, two, three, and four months in the future back to 1997.[128] Figure 19 below shows the ratio of the future contract price to the eventual spot price for each month.[129] While some periods have been more volatile than others, there have been few if any periods where the futures price ended up aligned with spot prices. In times of extreme volatility, futures prices for four months in the future can easily be more than 40% higher or lower than the spot price.

[128] https://www.eia.gov/dnav/ng/NG_PRI_FUT_S1_D.htm.

[129] The values associated with January 2020 show the ratio of the price of the January 2020 future contract from December 2019 ("M+1"), November 2019 ("M+2") October 2019 ("M+3"), and September 2019 ("M+4") divided by the January 2020 spot price.

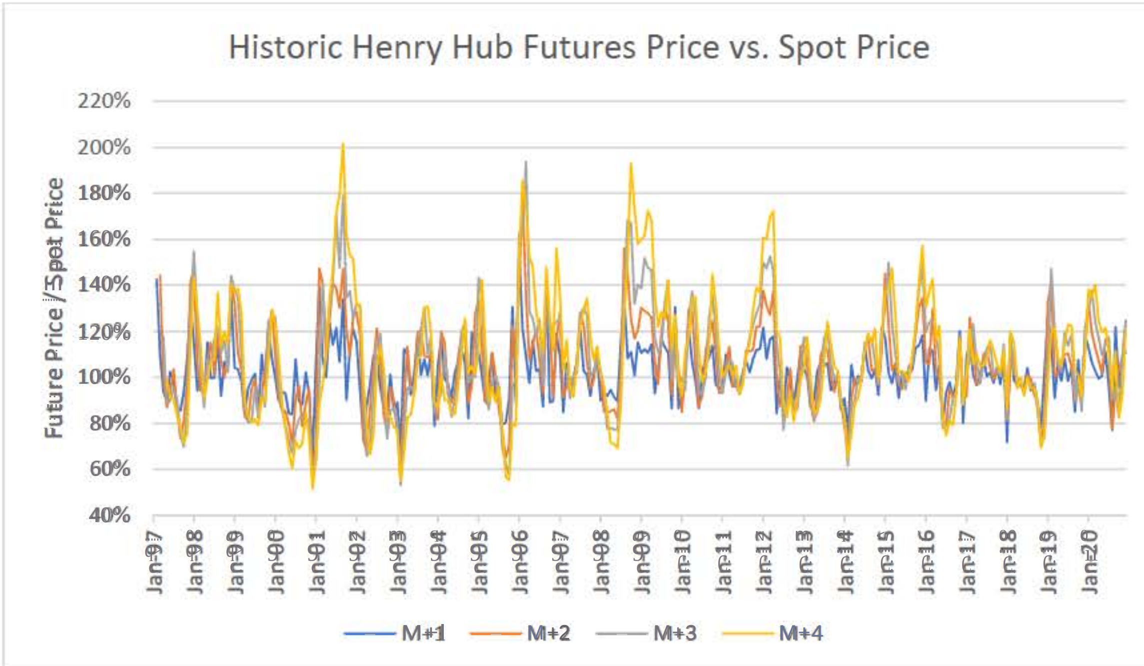

Figure 19 - Historic Henry Hub Futures Price vs. Spot Price

Q110. IS THIS VOLATILITY LIMITED TO THE NEAR-TERM?

A110. No. The price volatility of futures spans the time horizon of offered contracts, although the price swings are most pronounced for contracts in the subsequent 12 months. Figure 20 below shows changes to the daily settlement curve for futures from January 20, 2021 through January 28, 2021.[130]

[130] Data obtained from CME Group at https://www.cmegroup.com/ftp/settle/.

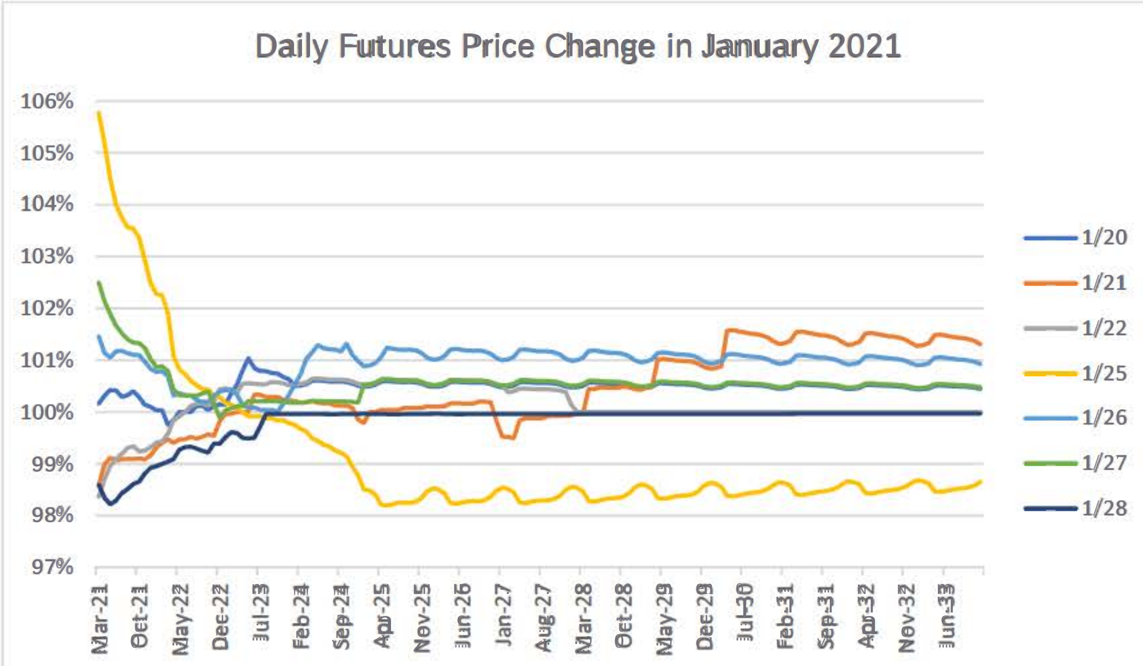

Figure 20 - Daily Futures Price Change in January 2021

The lack of liquidity's impact on price formation is clearly delineated in this chart. Daily changes for near-term futures on the left side of the graph show sizable, variable, and continuous changes from month-to-month, reflecting the higher volume of trades across those contracts. By contrast, the daily changes past January 2024 are almost always constant step-changes of 0.5% increments overlaid with small seasonal variations. For instance, the yellow line representing the change from 1/24/21 to 1/22/21 (the previous market day) reduced out-year contract prices by roughly 1.5% from 2025 through 2033. The very next day, the light blue line showing the change from 1/25/21 to 1/26/21 increased prices by roughly 1% from 2024 forward.

There is no rational underlying explanation for why the price of natural gas between four and twelve years in the future would suddenly and uniformly drop by 1.5% in a day only to rise suddenly and uniformly 1% the next day. And yet these types of daily moves are common, despite a complete dearth of daily policy changes that in theory could drive long-term shifts in supply and demand in the physical natural gas market that affect prices. Because of this arbitrary shifting, if Duke had obtained its 10-year swap on 1/25/21 instead of 1/22/21, its long-term price forecast would have been 1.5% lower for the duration of the IRP planning horizon.

C. *The Price Volatility Around Duke's Forecast Lock In Timing Highlights the Flaw of Using Futures for Long-Term Pricing*

Q111. DO THESE PRICE SWING TRENDS PERSIST OVER LONGER TIME FRAMES?

A111. Yes. While I do not have bulk access to daily historical futures price settlement data, I was able to extract the price of certain contracts at several dates over the past 18 months. Figure 21 below is a graph of the weekly price of a January 2022 futures contract going back to 2010.[131] When this future was first offered, the long-term forecasts for natural gas were suggesting much higher prices. As the fracking boom occurred and supply was increased, the price of the futures contract fell. Notice that while the January 2022 contract price followed the long-term downward trend consistent with new natural gas supply, major swings still occurred back in 2010 through 2012 that were not supported by the trading volume that was present over the past year (indicated by the bars in the lower-right corner of the graph).

[131] https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex html.

Figure 21 - January 2022 Futures Contract Weekly Price History

While Figure 21 above represents the price of only one futures contract for January 2022 as it evolved over time, Figure 22 below is a complex chart showing the price history of the January futures contracts from 2022 through 2030, with 2022 in blue, and 2023 through 2030 in progressively lighter shades of green.[132] I have also included small inset charts that show the futures price curve on specific dates, demonstrating the relationship between the spacing of lines on the main chart and that day's futures curve shape (high or low, inclined or flat).[133]

[132] This chart can be interpreted as snapshots of the shape of the futures curve graph that has price on the y axis and time on the x axis.

[133] The futures price curve is a chart with price on the y axis and time on the x axis. The inset charts represent the price of January forwards that were available on those dates.

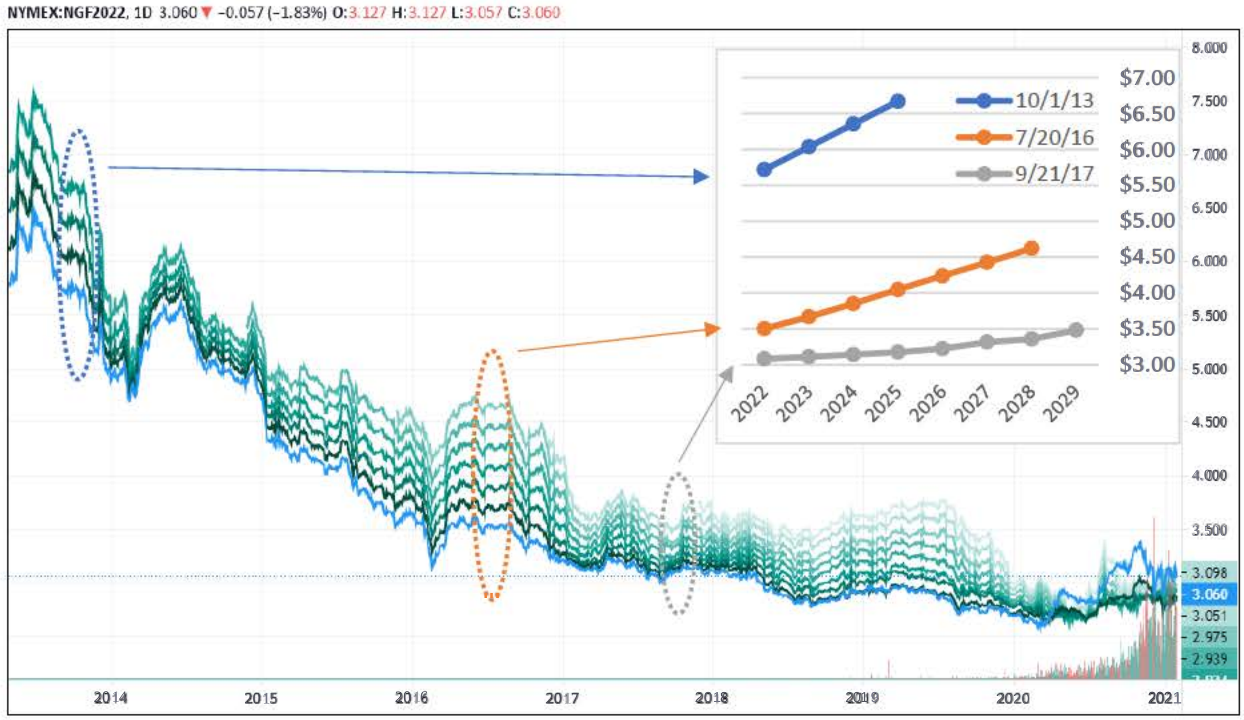

Figure 22 - Evolution of Natural Gas Futures Prices 2013-2021

On its own, this chart is somewhat difficult to interpret, but two key observations emerge. First is that for most of the past ten years, the graph of the futures prices had an upward-sloping trajectory. This is visible in the higher prices for successive years showing up in order of color. Sometimes, such as in 2013, the lines are further apart, indicating a steeper upward slope. Other times, such as in the summer of 2014, they are closer together, indicating a flatter slope. Second, the overall curve has fallen in absolute value over time, from in the $5.00 - $6.00 per MMBtu range in 2014 to the $2.75 - $3.75 per MMBtu range in 2019, reflecting the long-term increase in supply brought on by the fracking boom.

Q112. HAS THIS CONSISTENT, UPWARD-SLOPING FUTURES CURVE PERSISTED INTO THE RECENT PAST?

A112. No. Beginning in 2020, the dynamics of the futures contract market changed. Figure 23 below zooms in on the past eighteen months of data. The left side of the chart from summer 2019 mirrors the historic trends, with an upward sloping futures curve, albeit at lower absolute levels than in prior years. However, 2020 has broken from the past trends. The futures curve has moved around substantially, sometimes inverting (where short-term prices (blue) are higher than long-term prices (green)) only to quickly revert back weeks later.

Figure 23 - Evolution of Natural Gas Futures Prices 2019 - 2021

The rapid movement of the futures curve in 2020 means that the market prices that form the first ten years of Duke's natural gas price forecast were locked in at a time when volatility was at a recent high. Figure 24 below shows the January futures contract prices for 2022 through 2030 for selected dates in the past 10 months.[134] On March 9, 2020, the futures curve was still sloped steadily upward. By April 9, 2020, the front portion of the curve had inverted, while the out years' price had fallen roughly 7%.[135] A bit more than a month later, on May 14, 2020, the inversion deepened, and long-term prices fell further.

[134] January contracts typically have the highest prices of the year and are used as a proxy for the underlying fuel price over time.
[135] April 9, 2020 was the date that Duke used to establish its natural gas market price forecast and its high and low natural gas price forecasts. Exhibit KL-17.

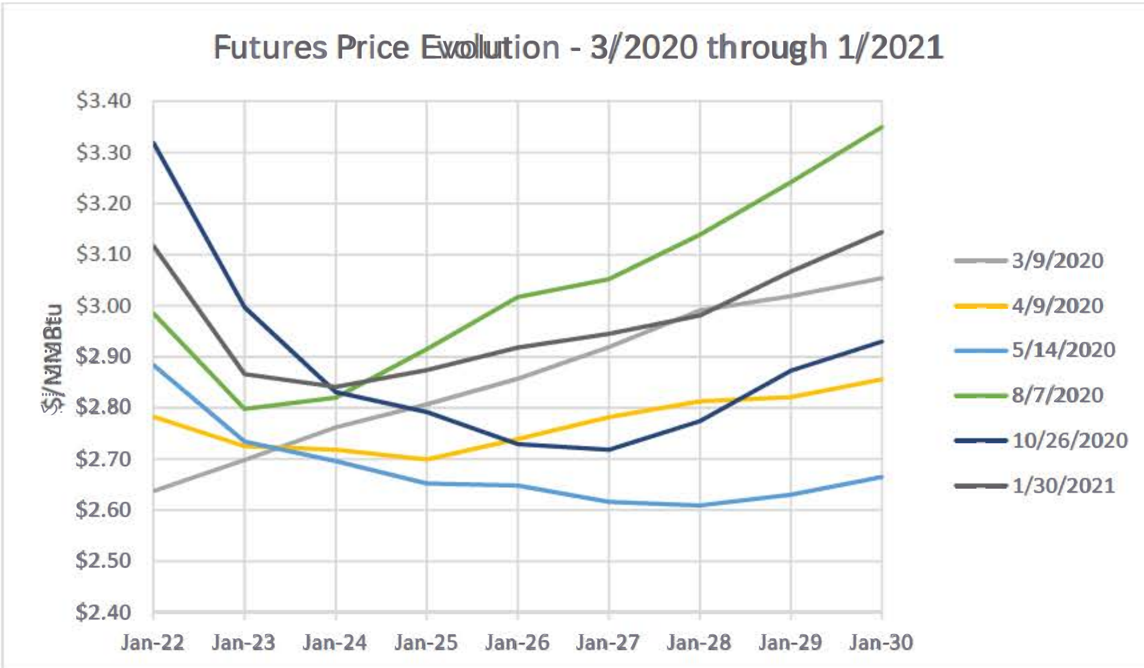

Figure 24 - Futures Price Evolution - 3/2020 through 1/2021

But this position was not held for long. By August 7, 2020, there had been a steep climb of the curve, with the inversion gone for all but 2022 and 2030 prices rising more than 25% from their May lows. By the end of October 2020, the curve shifted dramatically again; the inversion was back and stronger than any time in the previous year. Finally, at the end of January 2021, the inversion shifted again, with near-term prices falling while long-term prices rose.

Q113. DO THESE RAPID AND MAJOR SHIFTS IN THE FUTURES CURVE SIGNAL CORRESPONDINGLY MAJOR SHIFTS IN THE FUNDAMENTAL DYNAMICS OF THE NATURAL GAS MARKETS?

A113. No. The fluctuations in 2020 are most likely due to short-term supply, demand, and storage constraints combined with the sizable uncertainty due to COVID working their way into long-term forecasts. This is similar to what was shown above in Figure 20, where out-years had identical changes from day to day. If one strings together enough consecutive days of hot summer weather or mild winter weather expectations on top of the rapidly evolving coronavirus situation, the 0.5% daily changes can add up.

But to suggest that the fundamentals of the U.S. natural gas that drive long-term supply and demand jerked up and down in 2020 to this degree is to misstate the nature of "fundamentals". Figure 25 below shows a simplified version of Figure 23 above with only a few selected dates. The darker green lines represent near-term contracts while the lighter represent long-term contracts.

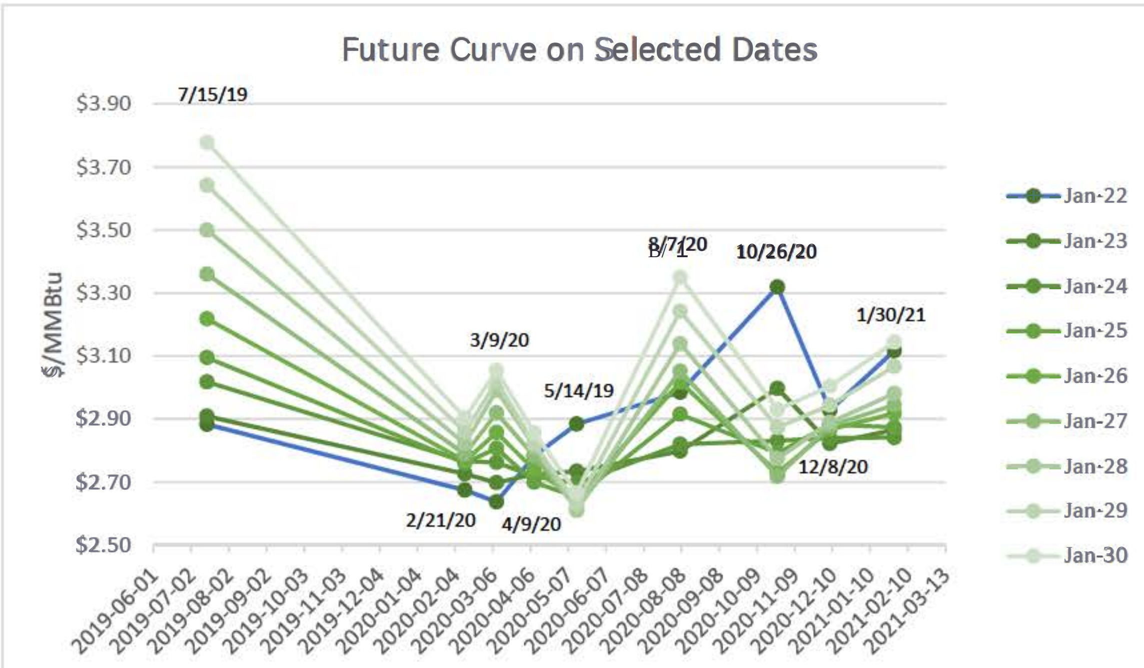

Figure 25 - Future Curve on Selected Dates

Q114. WHAT DOES THIS MEAN FOR DUKE'S NATURAL GAS FORECAST?

A114. Duke locked in its market price forecast for natural gas and its high- and low-price natural gas price sensitivities on April 9, 2020, right in the middle of a major period of volatility in futures markets, and very near to the lowest price point in the market in several years. Had the swap been priced a bit earlier or later, the natural gas prices for the first 15 years of the IRP would have been substantially different, potentially producing substantially different IRP results as well. Figure 26 below shows the percent change in the January futures contracts on certain dates compared to Duke's annual market price forecast.

[redacted]

Figure 26 - January Futures Price vs. Duke Swap Price

If Duke had locked in prices a month earlier, its gas price forecast from 2025 through 2030 would have been [redacted]% to [redacted]% higher, a non-trivial amount. If they locked in prices a month later, the prices would have been [redacted]% to [redacted]% lower. If they had refreshed their forecast in the summer, prices could have been [redacted]% to [redacted]% higher. These are not small variations, nor can they be considered forecast sensitivities. They are simply the result of relying too long on highly volatile prices from financial derivatives to establish or influence prices for all 15 years of the IRP planning horizon.

Nor can this issue be blamed on the strange and hopefully-not-repeated circumstances of 2020 and the COVID crisis. As shown in Figure 22 above, there have been plenty of times in the past when the entire futures curve shifted up or down substantially in a short period. For instance, early 2016 saw prices falls rapidly only to recover a few months later, and early 2017 featured a substantially flattening of the futures curve over the span of weeks.

D. Duke Should Utilize Only Eighteen Months of Market Prices Before Transitioning to a Fundamentals Forecast

Q115. GIVEN THE MAJOR ISSUES ASSOCIATED WITH MARKET PRICES DISCUSSED ABOVE, DO YOU BELIEVE THAT MARKET PRICES HAVE ANY ROLE IN ESTABLISHING DUKE'S NATURAL GAS FORECAST?

A115. Yes, although their role should be limited. I have shown above that the price of the ten-year swap that Duke uses is nearly identical to the price of futures contracts, and thus the issue with illiquidity and volatility in futures market prices translates into to swap prices. I have also shown that the long-term portion of the futures curve reflects short-term volatility in a manner that is inconsistent with deep structural changes to the natural gas market that would drive such divergence in actual long-term prices. Finally, I have shown that locking in a forecast mere weeks earlier or later can have outsized impacts on ten years of market prices.

In response to this, Duke should limit its use of market prices to the near-term and take steps to avoid the daily volatility inherent in natural gas derivative markets. I recommend that the Company calculate the market price of futures contracts three years forward using the average of the daily settlement price for the month preceding the earliest contract closing date. I also recommend that Duke calculate the average based on the most recently available report from at least two fundamentals-based forecasts such as EIA AEO or IHS Markit. I further recommend that Duke use market prices for 18 months, transition linearly between market prices and a fundamentals-based forecast over the next 18 months and proceed fully on the fundamentals forecast for month 37 and forward.

Q116. HOW WOULD THIS WORK IN PRACTICE?

A116. Duke began modeling for this IRP in summer 2020. If the Commission determines that Duke has not met its obligations under Act 62 and must update its modeling, it must render that decision by June 28, 2021.[136] In that instance, Duke should update its modeling to use market

[136] Details for Docket 2019-224-E, https://dms.psc.sc.gov/Web/Dockets/Detail/117181. Accessed 1/29/21.

prices starting in July 2021. The Company would determine the forward market price by averaging the settlement prices between May 17, 2021 and June 28, 2021 for July 2021 through June 2024 futures contracts.[137] There is no need for Duke to obtain or procure quotes from ten-year fixed swaps as it has been shown that these prices are functionally equivalent to the futures prices in the near term.

Duke would then obtain the most recent fundamentals-based forecast from at least two reputable sources. One of these sources should be EIA's AEO as it is a broadly available, open-source model that is readily available to intervenors. Duke would use market prices for the first 18 months, transition linearly to the average of the fundamentals-based models, and exclusively use the average of the fundamentals-based model after month 36.

Q117. DO YOU HAVE ANY INFORMATION HOW OTHER UTILITIES HANDLE THE MIX OF MARKET PRICES AND FUNDAMENTALS-BASED IN DEVELOPING THEIR NATURAL GAS PRICE FORECASTS?

A117. Yes. The Staff of the North Carolina Utilities Commission ("NCUC") conducted a survey of several utilities in the Southeast and around the country and "did not identify any utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years."[138] Further, other Duke subsidiaries in Florida, Kentucky, and Indiana relied on market prices for five years before transitioning over five year to fundamentals-based forecasts.[139]

Other utilities studied by NCUC Staff included TVA (which transitioned fully to fundamentals-based forecast in year six), Georgia Power (using the current year plus two years of market prices), Southwestern Public Service Company (a simple average of market prices and three fundamentals-based forecasts from the beginning of the planning horizon), and Puget Sound Energy (three years of market prices before switching to a fundamentals-based forecast). DEC and DEP are clear outliers.

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[137] Futures contracts close three days before the end of the calendar month.

[138] Initial Statement of the Public Staff at 22, February 12, 2019, Docket No. E-100, Sub 158, North Carolina Utilities Commission.

[139] *Id*.

Q118. DUKE HAS COMPLAINED IN THE PAST THAT FUNDAMENTALS-BASED MODELS IN GENERAL AND EIA'S AEO IN PARTICULAR LAG MARKET PRICES AND ARE THUS INEFFECTIVE IN PREDICTING PRICES IN THE NEAR TERM. WHAT IS YOUR RESPONSE TO THIS CRITIQUE?

A118. Duke's critique that fundamentals-based forecasts are slower to react to short-term pricing trends is not without merit; however, the directionality of the time lag cuts both ways. In its arguments in North Carolina's Avoided Cost proceeding, Duke suggested that its market purchases "demonstrate the stability of long-term natural gas market prices over the past few years" compared to fundamentals-based forecasts.[140] In support of this statement, it produced a low-resolution graph showing that market prices had flatter increases and were more closely bunched than fundamentals-based forecasts. This figure is reproduced below as Figure 27.

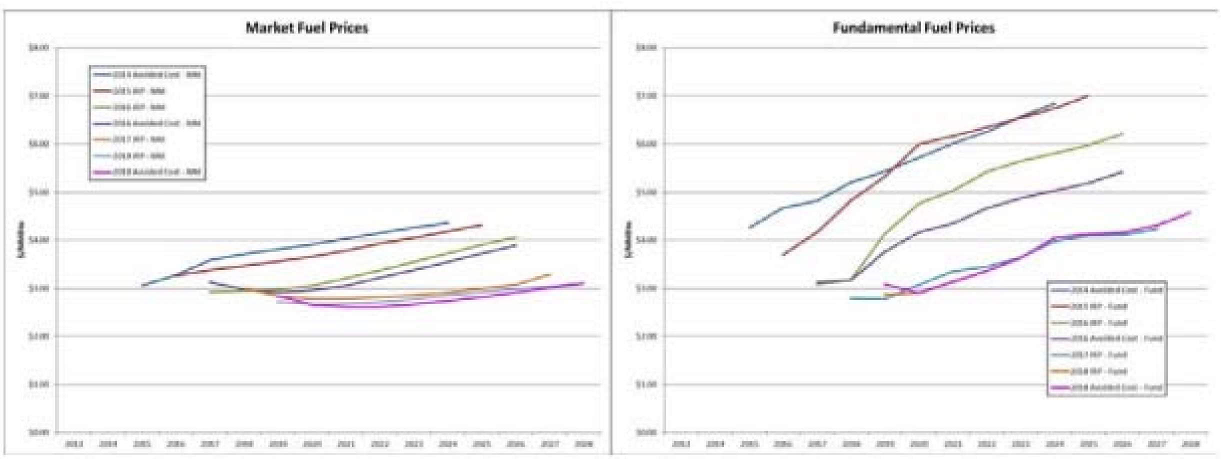

Figure 27 - Duke NC Avoided Cost Proceeding Market Prices vs. Fundamentals Chart

The left graph shows the ten-year forward price of market purchases made between 2014 and 2018 in IRP and avoided cost proceedings, while the right graph shows "fundamental fuel prices" over the same time frame. Duke did not publicly disclose the sources of these figures, but one can reasonably assume that the market prices are based on previous small swap

[140] See e.g. *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress* at 18, LLC at 18, Docket No. E-100, Sub158, State of North Carolina Utility Commission. March 27, 2019. (NC Avoided Cost proceeding).

purchases and the fundamentals based on forecast from groups such as EIA AEO or IHS Markit.[141]

Q119. WHAT DO YOU OBSERVE ABOUT THESE FIGURES?

A119. As an initial matter, the projections embedded in these charts are of little consequence. These figures were produced on March 27, 2019, meaning that any price projection past that time was unknown and could not be verified against actual results.[142] Duke cannot claim that market price forecasts are more accurate than fundamentals-based forecasts in the future until we reach the future.

EIA has produced a retrospective analysis of its forecasts going back to 1993 that compares the projections of future years to the actual prices that are realized.[143] Figure 28 below shows the forecast error for its AEOs from 1994 through 2020, with darker lines corresponding to earlier forecasts and lighter lines corresponding to more recent forecasts. Forecasts from early AEOs (darker lines) were consistently below eventual market prices, while those from later AEOs (lighter lines) were consistently above eventual market prices.

[141] DEP IRP Report at 5.
[142] And as shown above, these whims can be quite significant.
[143] Annual Energy Outlook Retrospective Review. Available at https://www.eia.gov/outlooks/aeo/retrospective/.

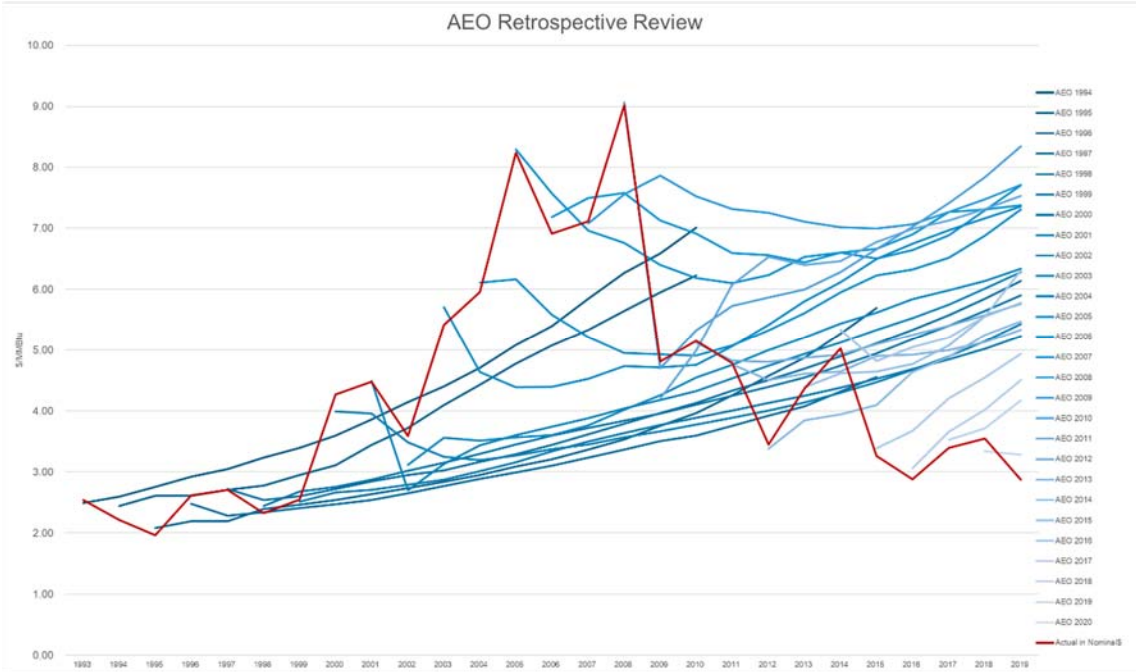

Figure 28 - AEO Retrospective Review – Natural Gas Prices

Figure 29 below shows the forecast error of the myriad AEOs. The lagging nature of fundamentals-based forecasts is evident, although the magnitude of its error has fallen in recent years. In forecasts just before the fracking boom drove down prices (e.g. AEO 2008-2010), estimates for future prices were substantially higher than prices that were eventually realized. But during periods when natural gas prices were rising faster than anticipated (e.g. AEO 2000-2003), forecasted prices were substantially under market prices.

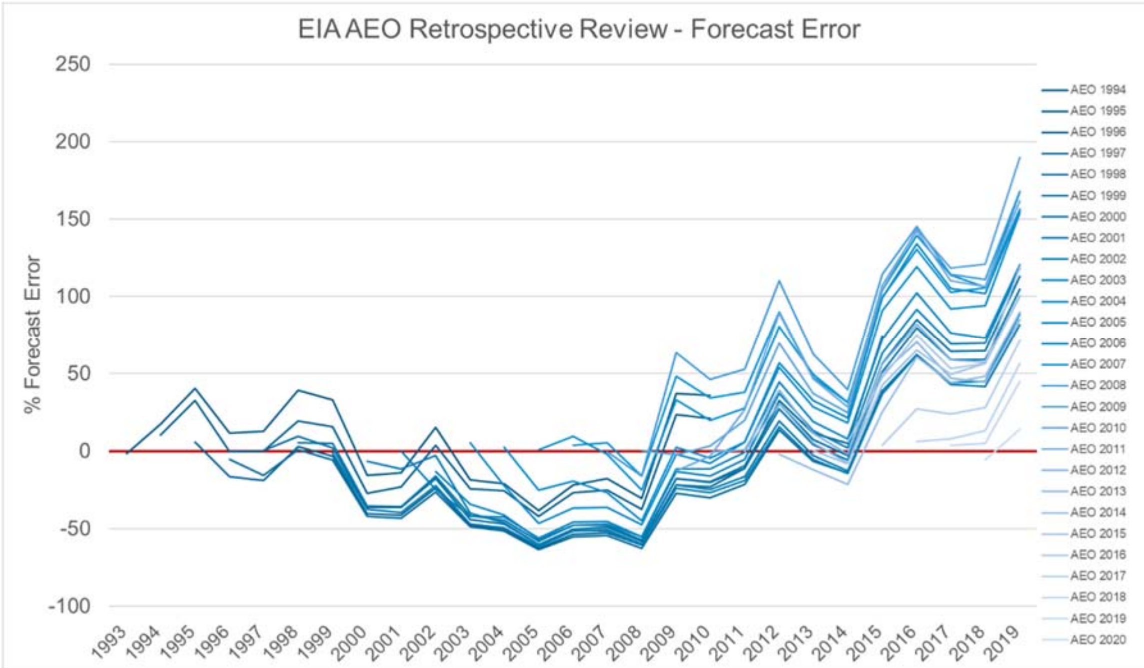

Figure 29 - EIA AEO Retrospective Review - Forecast Error

Despite Duke's previous protestations, similar forecast errors are also present in market prices. Figure 21 above showed the price of the January 2022 future dating back to 2013. In the summer of 2013, corresponding to the release of AEO 2012, the market projected that the price of natural gas in January 2022 would be $6.42 / MMBtu. AEO 2012 projected that it would be $6.022 / MMBtu.[144] In March 2020, the market thought the price for January 2022 natural gas would be $2.70, in October 2020 it thought it would be $3.20, and in late January 2021, it thinks it will be $3.12. Regardless of where the actual price of natural gas falls in January 2022, both the market and AEO long-term forecasts missed by similar amounts. This informs my recommendation to use the average of at least two fundamentals-based forecasts for the long-term portion of the natural gas price forecast.

Q120. ARE THESE TYPES OF FORECAST ERRORS PRESENT IN OTHER CRITICAL DATA POINTS IN THIS IRP?

[144] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2012&cases=ref2012&sourcekey=0.

A120. Yes. Duke's load forecast shows a similar forecast error, albeit with a slower correction than appears to be occurring in the AEO natural gas forecast. Figure 30 below shows the running ten-year forecast for DEC summer peak demand from 2012 through 2020.[145] DEC's summer peak demand actually shrunk at a compound annual growth rate ("CAGR") of -0.37% between 2010 and 2020 (solid red), while the weather-normalized values rose at a mild 0.06% CAGR (dashed red). Despite these consistent results, each year between 2010 and 2020, Duke's annual forecast for DEC summer peak demand continued to project load growth. Its forecast increased at rates of roughly 1.7% per year in the early 2010s before falling to roughly 1.0% per year in recent years, despite clear evidence of flat to declining load growth.

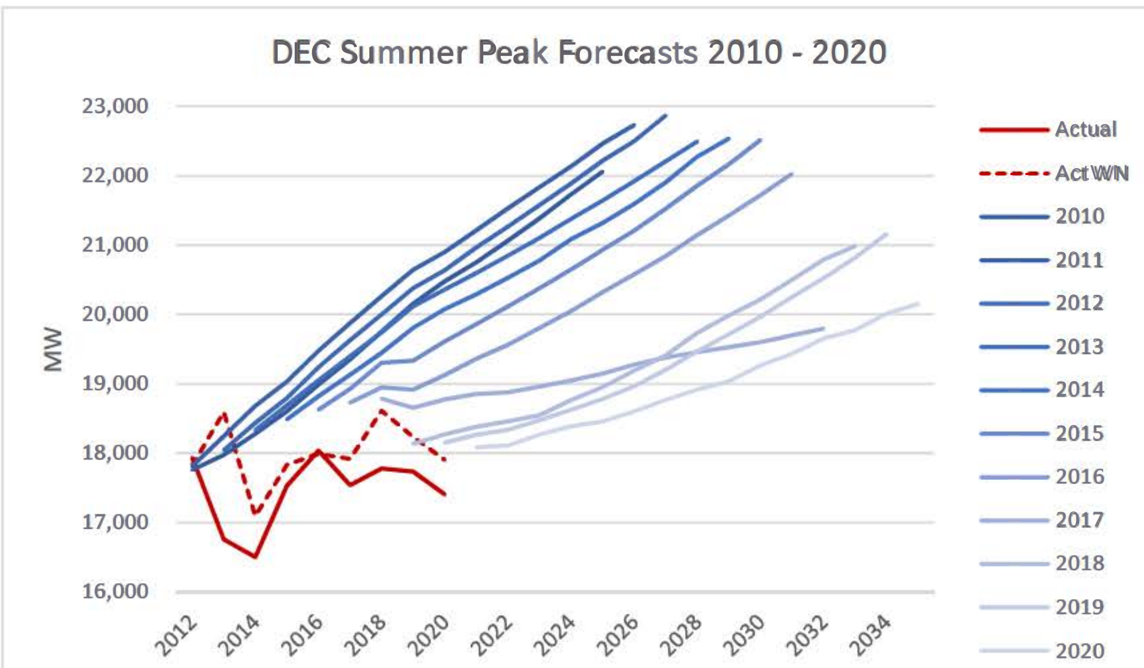

Figure 30 - Duke DEC Ten Year Summer Forecast

[145] Exhibit KL-18, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-12).

E. Duke's High and Low Natural Gas Price Sensitivity Methodology Exacerbates the Flaws of Using Market Prices in the Long-Term

Q121. DOES ACT 62 PROVIDE GUIDANCE ON FUEL FORECAST REQUIREMENTS?

A121. Yes, it does. Act 62 requires utilities to produce "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks."[146] To fulfill this obligation, Duke produced a high and low natural gas price sensitivity. However, it did not produce any price sensitivities on coal, using a single base value for that fuel cost in all of its scenarios.[147]

Q122. HOW DID DUKE CONSTRUCT ITS HIGH AND LOW NATURAL GAS PRICE SENSITIVITY?

A122. Duke once again used a blended approach. It first produced a high- and low-price sensitivity for its market price forecast for years 1 through 10 before transitioning linearly to the high and low sensitivities of the AEO forecast from years 11 through 15 before moving fully to the AEO high and low sensitivities in year 16 forward.

The market price sensitivities were constructed through a statistical approach called a "geometric Brownian Motion model."[148] This model iterates through time, applying random increases or decreases in prices based on observed volatility of the natural gas futures market. Each run of the model will produce a slightly different futures curve, reflecting the randomness of Brownian motion.[149] Duke produced 1,000 futures price curve simulations and sorted them high to low, averaging the 95th through 105th result for the low price (10th percentile) estimate and 895th through 905th result for the high price (90th percentile) estimate. This process was repeated 10 times with Duke averaging each run's high and low price to produce the final high and low simulated futures curve.

[146] S.C. Code Ann. § 58-37-40(B)(1)(e)(iii).
[147] DEC IRP Report at 157.
[148] Exhibit KL-17.
[149] Brownian motion describes small, random motion of particles in a medium. It is the mechanism through which diffusion occurs.

Q123. WHAT IS THE UNDERLYING CAUSE OF THE RESULTING 10TH AND 90TH PERCENTILE FUEL FORECAST SCHEDULES USING THIS METHOD?

A123. Randomness. This approach is roughly equivalent to using a Plinko board to produce fuel price sensitivities.[150] The underlying price volatility (i.e. daily price fluctuations driven by factors such as weather) is a measure of how quickly each iteration can deviate from that month's central value price. As the model iterates, most results will "revert to the mean" and remain relatively close to the central value of the baseline forecast. But in some runs, like in Plinko, the final value manages to migrate substantially to the high or low side of the distribution through random chance. If one were to graph the results of the 10,000 runs, one would expect to see a progressively wider normal distribution around each successive month's central value.[151]

Q124. HOW DOES THIS APPROACH CONTRAST WITH THE FUNDAMENTALS-BASED APPROACH TO HIGH- AND LOW-PRICE SENSITIVITIES?

A124. While Duke's market price sensitivities rely on randomness to determine high and low prices, fundamentals-based models tweak parameters in their highly-integrated model to simulate shifts in supply or demand that will cause prices to rise or fall. EIA's AEO has two scenarios that specifically adjust production and supply of oil and natural gas: "In the High Oil and Gas Supply case, lower production costs and higher resource availability allow higher production at lower prices. In the Low Oil and Gas Supply case, EIA applied assumptions of lower resources and higher production costs."[152] In these scenarios, prices are not based on random price volatility in a futures market already struggling to deliver robust long-term projections,

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[150] Plinko was a popular game that debuted on the Price is Right in 1983. It featured a pegboard with many rows of offset pegs set in a hexagonal pattern. Contestants would drop discs in the top of the board where they would randomly bounce left and right while falling through the rows of pegs. The discs eventually finished in a slot at the bottom of the board which contained a specific cash prize.

[151] This assumes the volatility of price swings is symmetric. If the initial data set has a higher chance of prices increases than price decreases, then the distribution will be skewed towards higher prices.

[152] *Critical Drivers and Model Updates*, EIA AEO 2020. Available at https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Critical%20Drivers%20and%20Model%20Updates.pdf.

but rather rise and fall in a manner that simulates and incorporates the economic feedback loops that would come along with supply changes.

Q125. HOW DO DUKE'S HIGH AND LOW MARKET PRICE FORECASTS COMPARE TO THE HIGH AND LOW AEO PRICE?

A125. The baseline market price forecast limits the range of the high and low market price sensitivities in the early years. This produces a result where the high market price sensitivity is actually lower than the AEO Reference case between 2025 and 2034, and is much lower than the price projected in the AEO Low Supply (i.e. high price) case. Similarly, AEO's High Supply (i.e. low prices) case is well above the low market price sensitivity. Figure 31 below shows this relationship, with NYMEX representing Duke's market price forecast.

[redacted]

Figure 31 - Fuel Price Sensitivity Comparison

Q126. DOES MERGER OF A RANDOM-WALK FORECAST AND A FUNDAMENTALS-BASED ALTERNATIVE SCENARIO FORECAST SENSITIVITY TO PRODUCE A UNIFIED HIGH-PRICE AND LOW-PRICE NATURAL GAS SENSITIVITY MAKE SENSE?

A126. No. There is no correlation between the statistical analysis Duke applied to the market prices to simulate high- and low-price sensitivities and the scenario-based AEO cases used to build the high- and low-price sensitivities in the fundamentals-based forecast. Merging the two together carries forward the flaws of Duke's baseline forecast into the natural gas price sensitivities required by Act 62.

The arbitrary nature of the resulting forecast is evident in the low gas price scenario. Figure 32 below, a reproduction of the DEC IRP Report Figure A-2, shows the implausible result that Duke's approach produces. Duke expects the natural gas industry to reduce prices after inflation by 3.5% per year in the 2020s, then increase at an annual rate of more than 18% between 2030 and 2035, before slowing growth to an annual rate of 2.9% from 2036 and beyond. **It is difficult to fathom a combination of policy scenarifos that would produce this curve exactly because no combination of policy scenarios would produce this curve.**

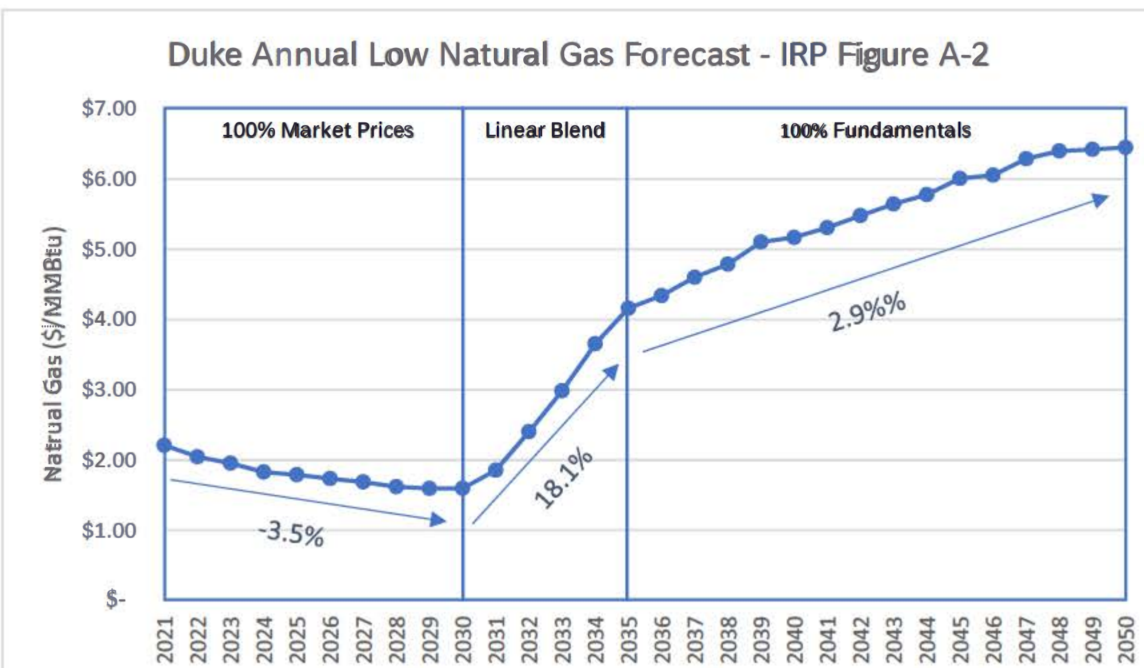

Figure 32 - Duke Annual Low Natural Gas Forecast - IRP Figure A-2

By contrast, the low-price scenario from AEO is internally consistent. Figure 33 below shows the annual results from this case overlaid with Duke's low-price sensitivity. Gone is the rapid directional switching, replaced by more modest moves as the feedback mechanisms in the fundamentals-based model incorporate higher supplies and lower prices.

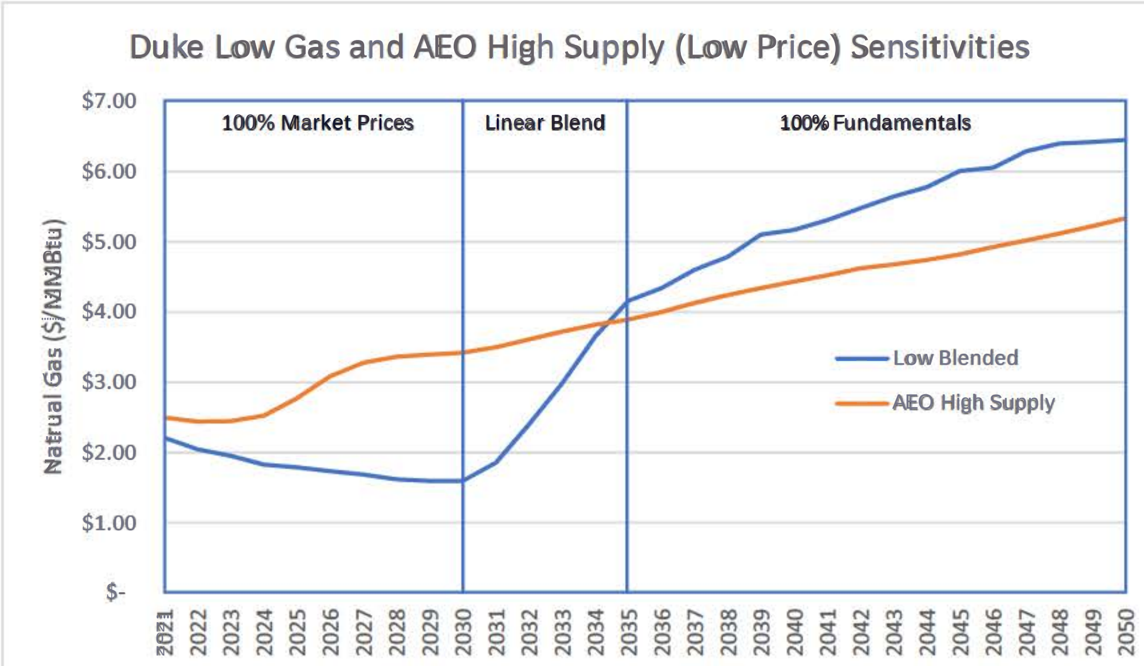

Figure 33 - Duke Low Gas and AEO High Supply (Low Price) Sensitivities

Q127. HOW DOES DUKE'S CHOICE TO USE THE 10^{TH} AND 90^{TH} PERCENTILE RESULTS IMPACT THE RESULTING SCHEDULE?

A127. The use of the 10^{th} and 90^{th} percentile results drove a larger discrepancy between the market prices and the fundamentals-based forecast. The high- and low-price sensitivities are important to demonstrate how Duke's fleet will respond to changes in the market, but using values from one-in-ten likelihood forecasts are more extreme and less likely than necessary for this purpose.

Even though under my recommendation market prices are only used for 36 months, the construction of the high- and low-price scenarios in that timeframe is still based on random chance based on the volatility of the market. I recommend that Duke instead use the 25^{th} and 75^{th} percentile results from this analysis. By selecting relatively more likely outcomes from the 25^{th} and 75^{th} percentile, the potential for the market prices to move too far from the central value is reduced.

Q128. DID DUKE CONSTRUCT SIMILAR FUEL COST SENSITIVITIES FOR COAL?

A128. No, it did not. Duke limited its fuel cost sensitivities to natural gas, stating: "By only changing natural gas prices, the impact on resource selection (CC vs CT vs Renewables) and dispatch (coal vs gas) can be evaluated."[153] Duke's failure to develop and analyze a high coal price scenario from either market conditions or regulatory changes, is problematic. Coal generation faces outsized regulatory risk and market pressures in the near future compared to the past. Changes in federal regulations may either require costly upgrades to maintain compliance or increase the running costs of coal units. For instance, EPA estimates that installing SCRs on units such as those at Marshall would cost roughly $100 million for a 300 MW unit and roughly $200 million for a 700 MW unit.[154] This could in turn impact the economic timeline for coal unit retirements, which could require additional replacement capacity to come online earlier.

Q129. WHAT DO YOU RECOMMEND WITH REGARD TO THE FUEL PRICE SENSITIVITIES?

A129. The issues shown above will disappear if Duke switches to the forecast methodology I described for the base scenario of relying on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts. The random nature of the Brownian model cannot move too far away from the central baseline market price forecast after only 36 months as there are simply fewer iterations to produce deviations. Maintaining the same blending method between 18 and 36 months will allow near-term market volatility to initially displace and then phase into the average of the early years prices from at least two fundamentals-based models.

I also recommend that Duke construct a high coal price scenario to reflect the increasing regulatory and market risk associated with the continued operation of its coal plants.

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[153] DEC IRP Report at 157.

[154] EPA Platform v6. Available at https://www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_5.pdf.

F. Duke's Reliance on Market Prices for Ten Years has Likely Skewed the IRP's Results

Q130. WHY IS THIS DISCUSSION ABOUT DUKE'S NATURAL GAS PRICE FORECAST IMPORTANT TO THE IRP?

A130. It is important because the natural gas price forecast and corresponding high- and low-price sensitivities are critical input assumptions to Duke's modeling. For a variety of reasons, Duke plans to close its coal facilities over the coming decades. The energy and capacity that these plants produce must be backfilled by some combination of resources. One of the primary goals of the IRP modeling is to determine which resource mix of demand-side management, renewable generation, fossil generation, and battery storage provides the most reasonable and appropriate blend. The natural gas fuel price input is particularly crucial in determining whether more renewables and batteries are selected by the model, or whether is it less costly to expand natural gas capacity (despite the stranded asset risk discussed previously).

Figure 34 and 35 below overlays Duke's annual central natural gas cost assumption with the additions from its modeling runs in the Base with Carbon Policy and Earliest Practicable Coal Retirement portfolios. Several thousand MW of new combined cycle plants are added in 2027 and 2028 in part based on the low natural gas prices that are prevalent through the early 2030s. If Duke's natural gas price forecast had reflected the recommended market price / fundamentals approach discussed above, prices in the mid-2020s and early 2030s would have been higher, increasing the PVRR of building and running natural gas plants.

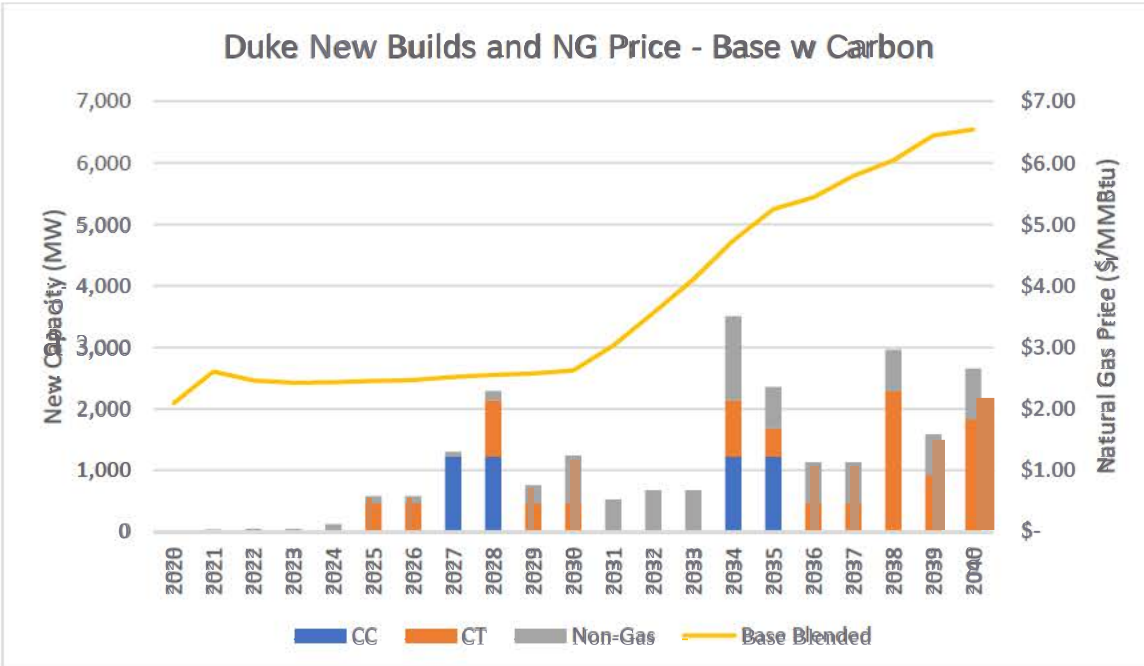

Figure 34 - Duke New Builds and NG Price - Base w Carbon

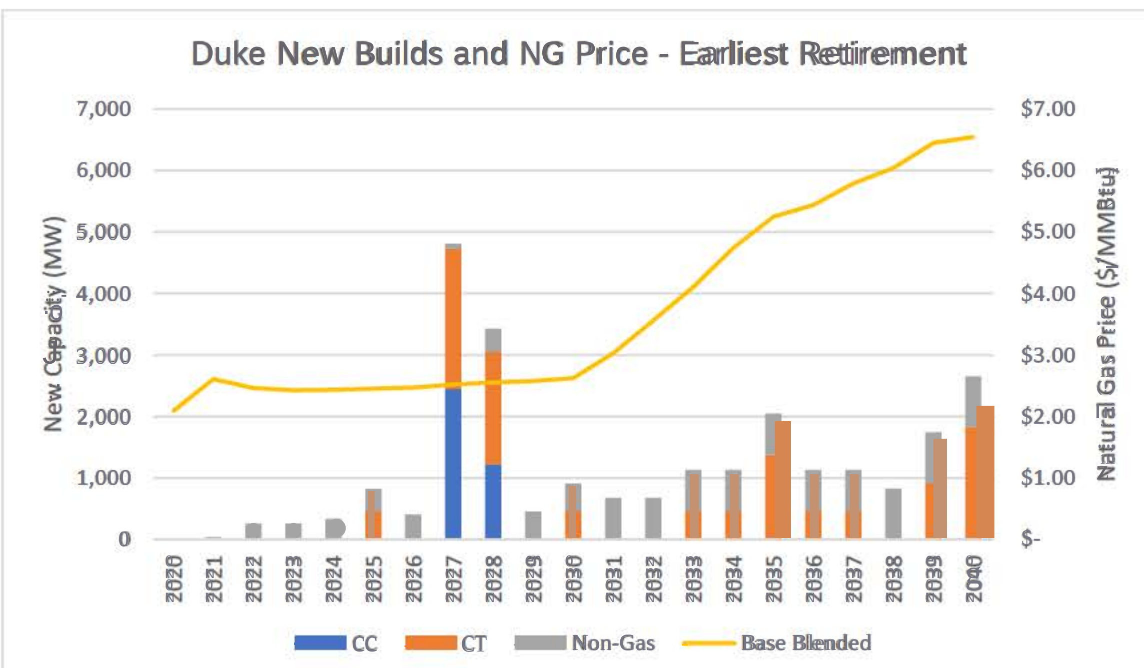

Figure 35 - Duke New Builds and NG Price - Earliest Retirement

Q131. DOES THE LOW NATURAL GAS PRICE FORECAST AFFECT OTHER MODELING OUTCOMES?

A131. It could affect the model's decision whether to add new renewable generation even when there is no capacity need, although as discussed in Section III above, Duke has not enabled this option. With a higher natural gas price forecast, running existing or constructing new natural gas facilities would be relatively more expensive. This would provide an opportunity for solar, wind, and battery resources to economically displace new builds of natural gas or substitute new renewable builds for existing natural gas generation.

Q132. HOW DOES DUKE'S FORECAST COMPARE TO THE METHODOLOGY YOU RECOMMEND?

A132. Duke's central near-term forecast based on market prices is well below the fundamentals-based models. Figure 36 below shows the annualized prices for the Duke's base forecast ("Duke Blend"), a newly updated blend based on my recommended methodology ("Updated Blend", and the full range of market prices ("NYMEX"), [redacted] forecast ("[redacted]"), and the 2020 AEO Reference case ("AEO Ref").[155]

[redacted]

Figure 36 - Original and Updated Natural Gas Price Forecast

The two fundamentals-based models track each other closely through roughly 2035, when [redacted] rises above AEO. By taking the average of these two forecasts, prices are projected to be quite a bit higher in the 2020s and the early 2030s than in Duke's original base forecast.

[155] Exhibit KL-19, Duke Response to SCSBA RFP 2 (producing Duke response to DR ORS 2-3).

This change would present the model's optimization routines with a very different picture when natural gas is at $[redacted] / MMBtu than when it is at $[redacted] / MMBtu.

Q133. DO YOU HAVE ANY FINAL OBSERVATIONS ON THIS ISSUE?

A133. Yes. It's tough to make predictions, especially about the future.[156] Duke's preference for long-term market price forecasts is fundamentally flawed. Ten years is simply too long to rely on contracts priced on highly volatile financial derivatives. The contracts that underpin Duke's market price forecast are subject to sizable and frequent price shifts. The long-term prices that form the basis for the first ten years of Duke's natural gas price forecast are derived from illiquid markets and inappropriately reflect short-term volatility in long-term prices. Further, the prices of these contracts can fluctuate wildly in the span of a few weeks. It is wholly inappropriate to base ten years of future fuel prices on what is essentially a toss of the dice.

Duke's refutation of fundamentals-based forecasts made in other proceedings falls flat. It is true that market prices, which settle daily, move faster than fundamentals-based models, which are updated once or twice a year. Yet the frequency with which market prices move is not necessarily reflective of more accurate pricing. The rapid and sizable price swings of 2020 clearly demonstrates that market prices ten years out can be substantially impacted by short-term market volatility. It is a fallacy to believe that policies that could drive 10% to 15% price changes ten years in the future would shift back and forth week to week.

Duke should change its natural gas forecast methodology to leverage market prices where they are most liquid, while appropriately blunting the natural volatility in natural gas futures markets. By constructing a market price forecast based on a full month of futures contracts settlement prices, Duke can temper the abundant short-term market price volatility. Using this market price forecast over eighteen months before fully transitioning to a fundamentals-based forecast over the next eighteen months leverages the information from the liquid futures market while not allowing it to overstaying its welcome. This approach should

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[156] RIP Yogi Berra.

also be applied to the high- and low-price sensitivities; Duke's current "random walk" approach to price variation has no place beyond three years.

The fundamentals-based forecast should be derived from the average of at least two reputable sources, including EIA's open-source AEO. This approach limits the reliance on one single forecast in much the same way that averaging a month of futures prices mitigates overweighting a single set of market prices. Marrying these two forecasts together should provide Duke with a much more robust natural gas forecast on which to base its IRP.

V. DUKE OVERLOOKS THE BENEFITS OF REGIONALIZATION

Q134. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A134. In this section, I discuss the role that regionalization could play in the planning and operation of Duke's system. I show how Duke's own modeling shows the benefit of enabling capacity sharing between DEC and DEP, and how increasing import capacity from neighboring regions could further reduce costs and increase reliability.

Q135. WHAT ARE YOUR PRIMARY FINDINGS?

A135. Duke has already performed modeling that shows the benefits associated with basic levels of regionalization, that is, firm capacity sharing between DEP and DEC and allowing for imports from neighboring systems. However, it has failed to pursue regulatory approvals that would let it operationalize some of these steps. Duke should proactively seek changes that would allow it to file joint IRPs between DEC and DEP and plan and operate its two companies in a manner that minimizes costs for all its customers.

Duke should also explore the potential benefits of broader regionalization through structures such as energy imbalance markets ("EIM") or regional transmission organizations ("RTO"). While Duke has supported the creation of the Southeast Energy Exchange Market ("SEEM"), due to its limited scope that organization would provide only a fraction of the potential benefits that a broader regionalization approach could bring.

A. *Increasing Regionalization can Reduce Costs and Increase Reliability*

Q136. PLEASE DESCRIBE THE BASIC TOPOLOGY OF DUKE'S POWER GRID AS MODELED IN ITS RESOURCE ADEQUACY STUDY.

A136. In Astrapé Consulting's DEP and DEC 2020 Resource Adequacy study ("RA Study"), it properly assumed that Duke's companies were interconnected to several neighboring systems. Figure 37 below is taken from the RA Study and shows the east and west region of DEP and DEC along with other systems such as TVA, PJM, and Southern Company.

Figure 1. Study Topology

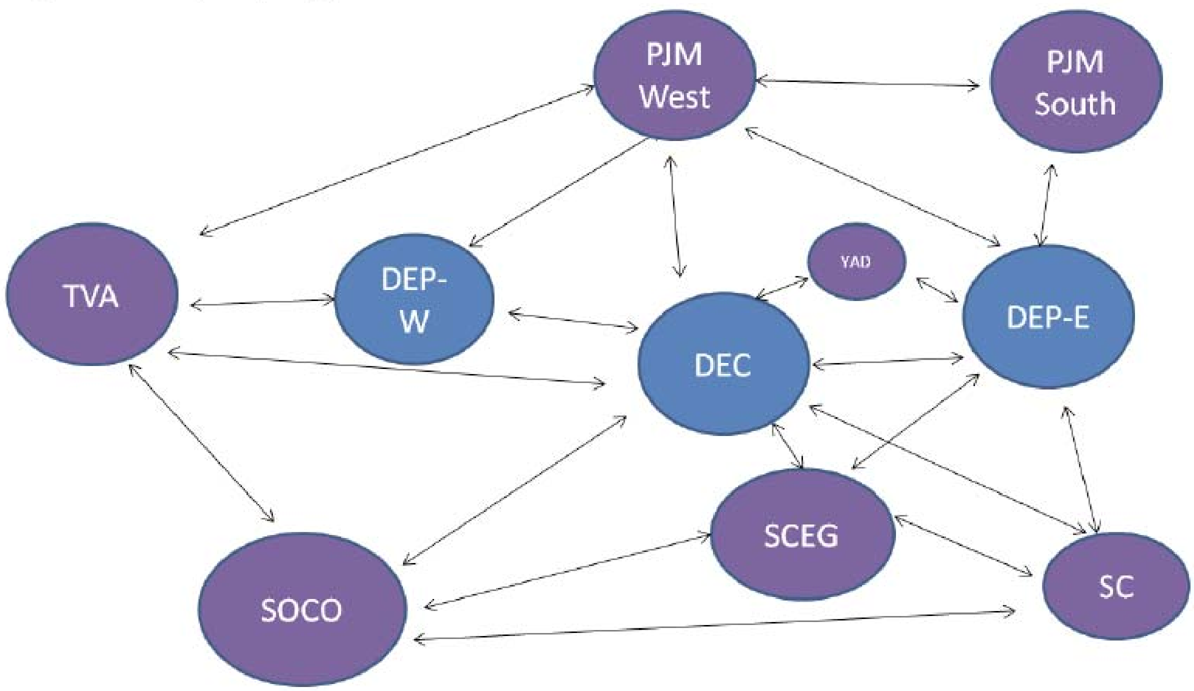

Figure 37 - Resource Adequacy Study Topology

Q137. HOW MUCH POWER CAN DUKE IMPORT FROM THESE REGIONS?

A137. The import limits vary based on the region. Table 6 below shows the import limits from each region in the summer and winter.[157] In addition to the figures below, DEC can export [redacted] MW to DEP-E, [redacted] MW to DEP-W, and transmit [redacted] MW from DEP-E to DEC to DEP-W.

[157] DEP IRP Attachment 3 Confidential Appendix_2020_Final, DEC IRP Attachment 3 Confidential Appendix_2020_Final.

For reference, DEP's and DEC's 2021 winter peak load forecast is 14,118 MW and 17,725 MW, respectively.[158]

From	Summer			Winter		
	DEC	DEP	Total	DEC	DEP	Total
SC	[redacted]					
SCEG	[redacted]					
SOCO	[redacted]					
TVA	[redacted]					
PJM West	[redacted]					
PJM South	[redacted]					
Yadkin	[redacted]					
CPLE	[redacted]					
CPLW	[redacted]					
Total	[redacted]					

Table 6 - DEP and DEC Import Capacity

Together, DEP and DEC have the ability to import [redacted] MW from neighboring balancing areas in the winter, in addition to DEC's transfer ability to DEP. This represents a substantial fraction of Duke's winter peak demand level.

Q138. DO ALL OF THESE OTHER REGIONS EXPERIENCE PEAKS AT THE SAME TIME AS DEC AND DEP?

A138. No. Astrapé performed a load diversity analysis and found that neighboring utilities had spare capacity during the times when either the regional system or DEC and DEP individually were at their peaks. During the overall winter system peak, individual regions were roughly 2%-9% below their individual peaks. Further, when DEC was at its peak, DEP was 2.8% below its peak load and other regions were between 3%-11% below their peak loads.[159] When DEP was at its peak, DEC was 2.7% below its peak load and other regions were between 3%-9% below their peak loads.[160] This suggests that not only do these other regions have the physical ability to provide capacity to DEP and DEC during their winter peaks, but they have capacity to spare as well.

[158] 2020 IRP_ Model Inputs_NON-CONFIDENTIAL.
[159] DEC RA Study at 28.
[160] DEP RA Study at 27.

Q139. WHAT IMPORT CAPACITY LIMITATIONS DID ASTRAPÉ AND DUKE USE IN ITS RA STUDY?

A139. Astrapé and Duke ran several scenarios that modified the import capacity limits. The first case was an "island" case, where all resources must be in the physical footprint of DEC or DEP. Unsurprisingly, this required a very high reserve margin to meet the standard of 0.1 LOLE per year, with a 22.5% requirement in DEC and a 25.5% requirement in DEP.[161,162] This island configuration is not reflective of how Duke's systems are physically configured, and thus Astrapé ran the Base case allowing imports from neighboring regions. This reduced the reserve requirement in DEC to 16.0% and in DEP to 19.25%[163]

Astrapé also modeled a "combined case" where both utilities were treated as a single entity. This model produced a combined reserve margin requirement of 16.75%.[164] One last sensitivity was performed that limited the imports into the combined utility to 1,500 MW, well below the actual import capacity. This adjustment increased the reserve margin to 18.0%, showing the cost benefits associated with utilizing spare regional capacity.[165]

Q140. DID THE COMBINED CASE RESULT IN DELAYS IN NEW CAPACITY?

A140. Yes. By modeling a Joint Planning case with a combined DEC and DEP, Duke was able to delay the addition of several CTs. It also resulted in a lower overall reserve margin. As Duke indicated, "[t]he ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEC and DEP when planning for capacity jointly."[166]

[161] Loss of Load Expectation. The 0.1 LOLE is roughly equivalent to experiencing one load shed event in ten years.
[162] DEP IRP Report at 67, DEC IRP Report at 65.
[163] DEP IRP Report at 67, DEC IRP Report at 65.
[164] DEC IRP Report at 66.
[165] DEP RA Report at 61.
[166] DEC IRP Report at 200.

Q141. DESPITE THE OBVIOUS BENEFITS ASSOCIATED WITH PLANNING AND MANAGING CAPACITY JOINTLY, DOES THE COMPANY CURRENTLY PLAN AND MANAGE CAPACITY JOINTLY BETWEEN DEC AND DEP?

A141. No, it does not. While the Company has a Joint Dispatch Agreement ("JDA") in place, outside of emergency situations, it is limited to economic non-firm energy transfers.[167] It also does not perform a unified IRP for the combined companies, nor plan for capacity jointly between the two companies.

Q142. WHY DOES DUKE NOT INTEGRATE ITS OPERATIONS AND PLANNING EFFORTS MORE THOROUGHLY?

A142. Duke's response to this question was that they currently do not have authorization to either submit a unified IRP[168] or share long-term capacity.[169] It further noted that such authorization would be required from the Federal Energy Regulatory Commission ("FERC"), the North Carolina Utilities Commission ("NCUC"), and the Public Service Commission of South Carolina ("PSCSC").[170]

Q143. IS ANYTHING STOPPING DUKE FROM PURSUING THESE AUTHORIZATIONS?

A143. There does not appear to be anything preventing the Company from pursuing these changes. Duke stated "[i]f and when a decision were to be made to file a unified IRP that covers both territories or to merge the balancing areas across [North Carolina] and [South Carolina], the Company would seek appropriate regulatory approvals."[171] The response is ambiguous as to who would be making the decision, but Duke did not identify any legal roadblocks to seeking a change in status.

Q144. WHAT DO YOU RECOMMEND ON THIS MATTER?

[167] Exhibit KL-20, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-12).
[168] Exhibit KL-21, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-13).
[169] Exhibit KL-20.
[170] Exhibit KL-20.
[171] Exhibit KL-22, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 4-2).

A144. I recommend the Commission direct Duke to study the impact of joint planning of and long-term capacity sharing across its two systems and prepare a feasibility study on merging these functions across the two utilities. Based on high-level analyses presented in this docket, it appears that cost savings are available through this effort. Arrangements could be made between DEC and DEP that would realize and pass these cost savings onto the customers of each utility.

B. *Duke Should Analyze the Benefits of Broader Regionalization*

Q145. ASIDE FROM POTENTIALLY DEEPENING ITS JDA TO INCLUDE PLANNING AND FIRM CAPACITY TRANSFERS, ARE THERE OTHER REGIONALIZATION BENEFITS THAT DUKE COULD CONSIDER TO FURTHER REDUCE COSTS TO ITS CUSTOMERS?

A145. Yes. Duke has already expressed interest in joining SEEM, a very small step towards regionalization that would allow companies to voluntarily execute bilateral contracts for as-available energy in fifteen-minute blocks. This marketplace could potentially save participating utilities in the Southeast \$40-50 million annually in the near term, potentially increasing to \$100-\$150 million in the long term.[172]

Q146. HOW DO THESE SAVINGS COMPARE TO THE POTENTIAL VOLUME OF ELECTRICITY SALES FROM THE FOUNDING MEMBERS?

A146. It is miniscule. Founding members of SEEM are expected to include some of the largest utility companies in the southeast, including Associated Electric Cooperative, Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, ElectriCities of North Carolina, Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company, and TVA.[173] Considering DEC and DEP spend billions of dollars annually apiece on electricity, \$40 million per year from this

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[172] https://news.duke-energy.com/releases/southeast-electric-providers-to-create-advanced-bilateral-market-platform.
[173] *Id.*

consortium of large utilities is a drop in the bucket of what benefits broader and deeper regionalization could bring.

Duke appears to acknowledge that SEEM will not be integral to its operations or planning going forward. When asked about how SEEM will change their IRP assumptions, Duke responded: "Since SEEM is a sub-hourly non-firm energy only market, SEEM is not expected to be foundational to future IRPs."[174]

Q147. ARE THERE OTHER STRUCTURES THAT COULD INCREASE SAVINGS FURTHER COMPARED TO SEEM?

A147. Yes. The Western EIM has more robust features, including both a 15-minute and 5-minute market and an independent market monitor.[175] Since its formation in in November 2014, the Western EIM has saved its participants $1.2 billion, including $325 million in 2020 alone.[176]

But even the Western EIM does not currently feature a day-ahead market, where the vast majority of energy transactions are handled, nor implement transparent nodal pricing (e.g. LMPs). These are features associated with regional transmission organizations ("RTOs") and represent an even deeper commitment to regionalization. RTOs such as PJM and MISO function as transmission system operators and coordinate wholesale markets in energy, capacity, and ancillary services. By extending planning and dispatch over a broad geographic area, RTOs can maximize the benefits of geographic diversity in load shape, weather, and generation assets. In contrast to the limited SEEM proposal, a broader southeast RTO could save customers up to $384 billion through 2040.[177]

Q148. HAVE THERE BEEN RECENT ACTIVITIES ON REGIONALIZATION IN SOUTH CAROLINA?

A148. Yes. Governor McMaster signed H. 4940 into law last fall.[178] This law creates a legislative committee and advisory board that has until fall 2021 to study changes to the electricity sector

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[174] Exhibit KL-6.
[175] https://www.westerneim.com/Pages/About/HowItWorks.aspx.
[176] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[177] https://caper-usa.com/news/south-carolina-law-pushes-for-power-market-reform-floats-creation-of-rto/.
[178] S.C. Act No. 187 (2020). Available at https://www.scstatehouse.gov/sess123_2019-2020/bills/4940.htm.

in South Carolina, of which the South Carolina President of Duke Energy is a member. The study must investigate potential reforms such as creating a new RTO, joining an existing RTO, establishing an EIM, restructuring power generation, and offering full customer retail electric choice.[179]

Duke should bring its expertise to the committee and help detail the potential benefits and challenges associated with regionalization. It will be critical that Duke provide information objectively, recognizing that some benefits of that come with regionalization could put downward pressure on Company revenues and profits. However, as shown by the buildouts needed to transform the electricity sector in South Carolina, there will be no shortage of investment opportunities in new, clean generation and transmission assets.

VI. CONCLUSION

Q149. PLEASE PROVIDE YOUR OVERALL CONCLUSIONS OF DUKE'S IRP.

A149. Duke's IRP fails to comply with Act 62 and the Commission should require modifications to its filing. The Company fails both to identify a single Preferred Resource Plan and to provide the Commission with sufficient information from which it could determine what is the most reasonable and prudent means to meet Duke's identified energy and capacity needs. Duke risk analysis is very limited and does not adequately address regulatory risks associated with its natural gas buildout or continued operation of coal plants in its Base portfolios. These risks are readily identified using a straight-forward analysis, demonstrating the downside economic risk of carbon prices, regulatory changes, or high fossil fuel on any scenario that does not rapidly move away from fossil fuels.

Duke's modeling methodology and input assumptions must be revisited. The recent extension of the federal ITC must be incorporated into solar and solar plus storage capital costs. Similar to DESC, Duke erroneously did not allow the model to add new capacity or PPAs

[179] *Id.* § 2(B).

unless there was a capacity need, eliminating the potential to incorporate less-expensive energy-only resources earlier in the planning horizon. Duke also overstated its PV fixed O&M cost assumptions and did not accurately reflect the existing or likely future mix of fixed-tilt vs. single-axis tracking systems. The Company failed to allow two-hour batteries despite their ability to provide meaningful capacity credit at lower costs. Finally, Duke's development timeline for SMR and pumped hydro do not comport with the Company's own data.

Duke natural gas forecast relies far too long on fickle market prices, a fatal flaw of that permeates its entire IRP planning horizon. This approach codifies long-term prices that are disproportionately impacted by short-term volatility and diverge substantially from prices projected by fundamentals-based forecasts, as is demonstrated vividly in the Company's high- and low-price sensitivities. The Company should instead rely on market prices for a much shorter period, using them for eighteen months before switching fully over to a fundamentals-based forecast by 36 months. It should also adjust its high- and low-price scenarios to reflect the 25th and 75th percentile results and develop a high-cost coal case to account for the myriad regulatory risks faced by coal generation.

Finally, the Company should embrace the cost savings that come with broader regionalization and begin to explore the implications of unifying its planning and operations of DEC and DEP. Duke should not be satisfied with the limited benefit of joining SEEM but should explore more robust regionalization strategies such as forming or joining an RTO.

If Duke were to make these updates to its modeling, it is likely that cost-optimal portfolios will feature earlier coal retirements, lower natural gas builds, and higher and earlier solar, solar plus storage, and standalone storage deployment. These updated portfolios will enable Duke's customer to reap the benefit of the federal ITC extension while jumpstarting Duke's progress towards its own 2050 net zero goals.

Q150. DOES THIS CONCLUDE YOUR TESTIMONY?

A150. Yes, it does.